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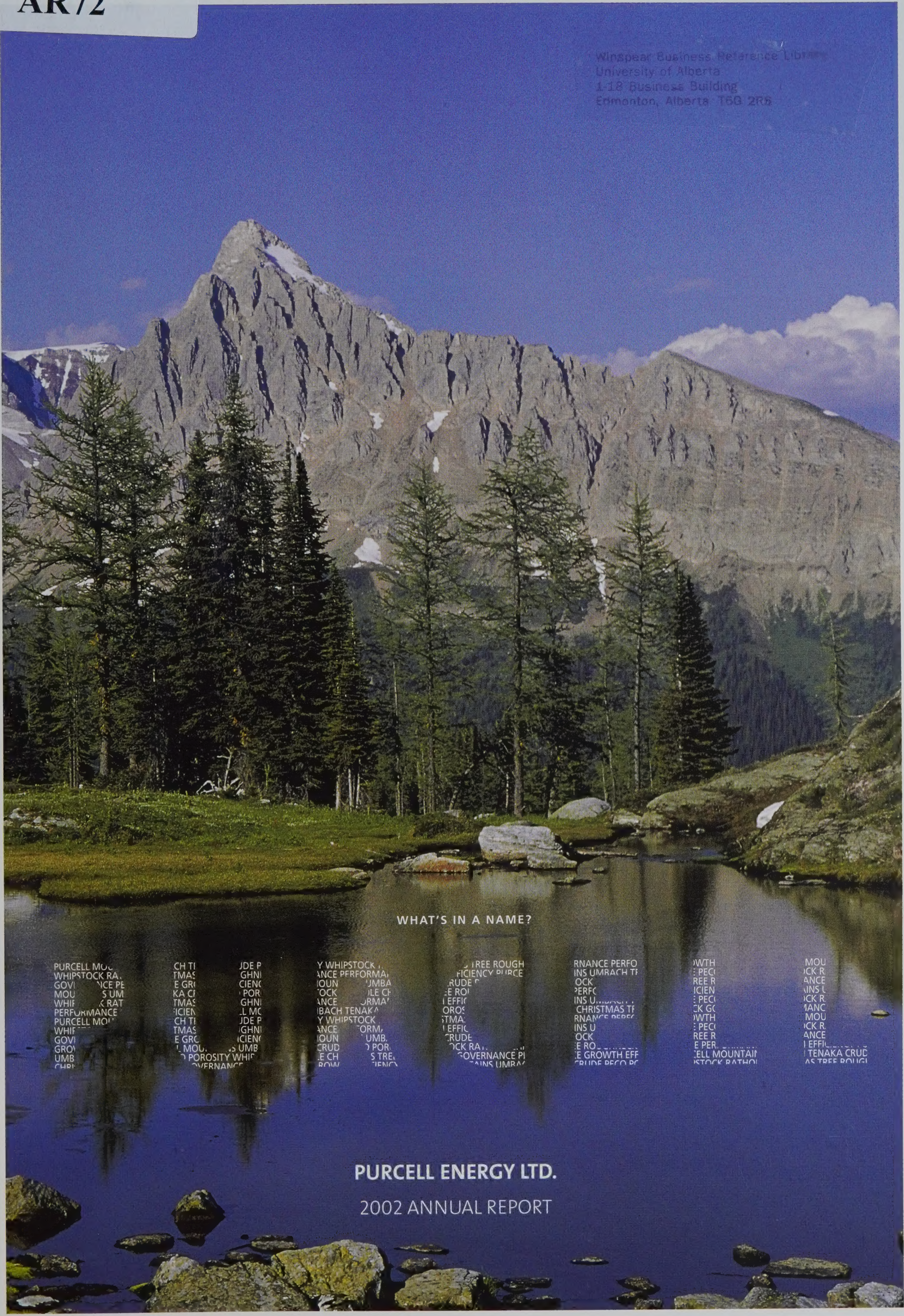
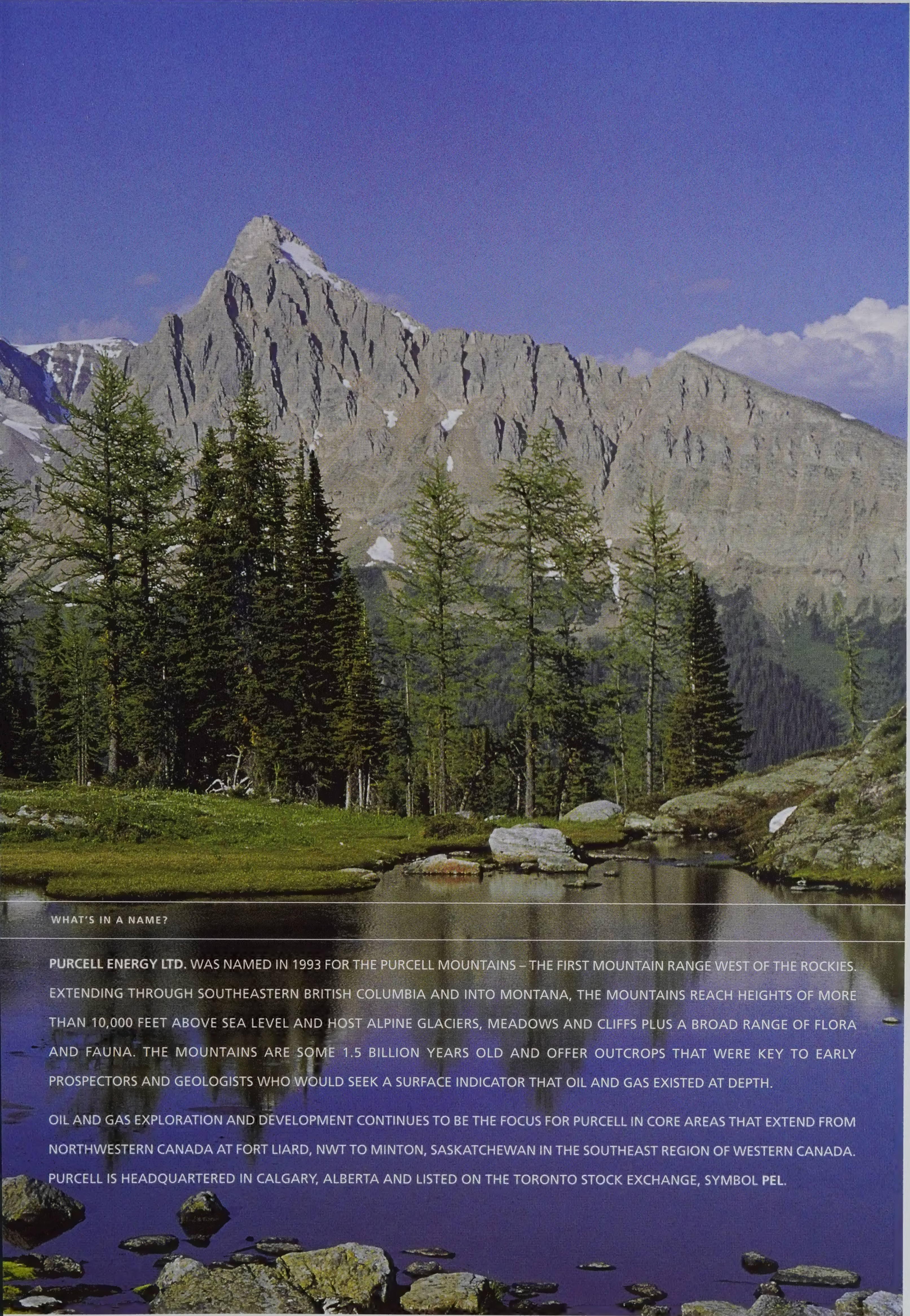


WHAT'S INSIDE

NOTICE OF ANNUAL MEETING

The Annual General Meeting for shareholders of Purcell Energy Ltd. will be held on Thursday, May 22, 2003 at 2:30 pm at the Metropolitan Centre, 333 - 4th Avenue SW, Calgary, Alberta. All shareholders are invited to the meeting but if unable to attend, are encouraged to send in the form of Proxy included with the annual meeting materials.



WHAT'S IN A NAME?

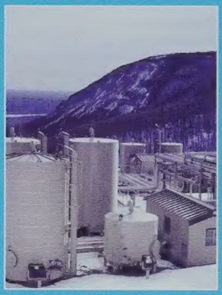
PURCELL ENERGY LTD. WAS NAMED IN 1993 FOR THE PURCELL MOUNTAINS – THE FIRST MOUNTAIN RANGE WEST OF THE ROCKIES. EXTENDING THROUGH SOUTHEASTERN BRITISH COLUMBIA AND INTO MONTANA, THE MOUNTAINS REACH HEIGHTS OF MORE THAN 10,000 FEET ABOVE SEA LEVEL AND HOST ALPINE GLACIERS, MEADOWS AND CLIFFS PLUS A BROAD RANGE OF FLORA AND FAUNA. THE MOUNTAINS ARE SOME 1.5 BILLION YEARS OLD AND OFFER OUTCROPS THAT WERE KEY TO EARLY PROSPECTORS AND GEOLOGISTS WHO WOULD SEEK A SURFACE INDICATOR THAT OIL AND GAS EXISTED AT DEPTH.

OIL AND GAS EXPLORATION AND DEVELOPMENT CONTINUES TO BE THE FOCUS FOR PURCELL IN CORE AREAS THAT EXTEND FROM NORTHWESTERN CANADA AT FORT LIARD, NWT TO MINTON, SASKATCHEWAN IN THE SOUTHEAST REGION OF WESTERN CANADA. PURCELL IS HEADQUARTERED IN CALGARY, ALBERTA AND LISTED ON THE TORONTO STOCK EXCHANGE, SYMBOL **PEL**.

Highlights

($000, except where indicated; 6 mcf = 1 bbl)	3 months to Dec. 31 2002	2001	% change	12 months to Dec. 31 2002	2001	% change
FINANCIAL						
Petroleum and natural gas sales	**9,978**	7,354	36	**30,746**	37,472	(18)
Revenue, net	**7,465**	6,372	17	**26,677**	30,406	(12)
Operating expenses	**2,353**	1,615	46	**7,880**	6,393	23
Per unit ($/BOE)	**6.83**	3.43	99	**5.37**	3.80	41
G&A expenses	**405**	722	(44)	**2,195**	2,024	8
Per unit ($/BOE)	**1.17**	1.53	(24)	**1.49**	1.20	24
Cash flow	**3,962**	3,685	8	**14,677**	20,717	(29)
Per share-basic ($)	**0.150**	0.150	-	**0.554**	0.821	(33)
Per share-diluted ($)	**0.148**	0.145	2	**0.544**	0.789	(31)
Net income (loss)	**(175)**	355	(149)	**1,090**	7,414	(85)
Per share-basic ($)	**(0.007)**	0.014	(150)	**0.041**	0.294	(86)
Per share-diluted ($)	**(0.007)**	0.014	(150)	**0.040**	0.282	(86)
Capital expenditures, net	**6,131**	9,282	(34)	**35,232**	37,093	(5)
Common shares outstanding (000)						
Weighted average, basic	**26,400**	24,553	8	**26,491**	25,230	5
Weighted average, diluted	**26,818**	25,349	6	**26,973**	26,248	3
End of period, basic	**27,641**	26,513	4	**27,641**	26,513	4
End of period, diluted	**31,179**	29,215	7	**31,179**	29,215	7
OPERATIONS						
Production						
Natural gas (mmcf/d)	**17.28**	26.96	(36)	**19.56**	24.46	(20)
Crude oil and liquids (bbls/d)	**864**	618	40	**763**	528	45
Equivalent (BOE/d)	**3,745**	5,111	(27)	**4,022**	4,604	(13)
Commodity prices (well head)						
Natural gas ($/mcf)	**4.19**	2.48	69	**3.06**	3.57	(14)
Crude oil and liquids ($/bbl)	**35.57**	21.01	69	**34.56**	29.02	19
Equivalent ($/BOE)	**27.56**	15.63	76	**21.45**	22.29	(4)

Message to Shareholders



PURCELL ENERGY IS A JUNIOR OIL AND GAS PRODUCER THAT IS KNOWN FOR PURSUING GRASSROOTS EXPLORATION – A GROWTH STRATEGY THAT HAS THE EXCITEMENT OF COMPANY-MAKER DISCOVERIES BUT REQUIRES PATIENCE FOR A MULTI-YEAR CYCLE FROM CONCEPT TO DISCOVERY TO MONETIZATION. THIS IS PURCELL'S TENTH YEAR IN THE CANADIAN OILPATCH, YET ANOTHER DISTINCTION FOR AN INDUSTRY THAT MORE TYPICALLY OFFERS JUNIOR COMPANIES A FIVE-YEAR LIFESPAN. OUR SUCCESSES AND OUR LONGEVITY COME FROM THE SAME SOURCE: A COMMITMENT TO GROWING A QUALITY BASE OF EXPLORATION OPPORTUNITIES, RESERVES AND PRODUCTION. PURCELL'S SHAREHOLDERS HAVE THE SECURITY OF A SOLID PRODUCTION BASE UNDERPINNING THE COMPANY AND EXPOSURE TO TREMENDOUS GROWTH POTENTIAL FROM EXPLORATION.

2002 is a year in which Purcell's investment and exploration activity positioned the Company for future growth:

- Fort Liard generated 55 percent of 2002 cash flow with natural gas production from three wells. A total of 16.5 billion cubic feet of sales gas net to Purcell have been produced since April 2000 to the end of 2002, averaging 15.8 mmcf per day from three wells during 2002 for the project area.
- A new opportunity at Fort Liard was pursued in early 2003 with the drilling of the 2K-29 directional well from the K-29 location that is expected to significantly enhance production from the area.
- Reserves at Fort Liard (less 2002 gas production) were confirmed with no revisions reflecting the quality of the Fort Liard reservoir, and reserves were added in other areas from successful drilling throughout western Canada.
- Up front investment in infrastructure at Rainbow in northwest Alberta supporting sour gas production to facilitate the long-term development of the area's potential.
- Undeveloped land increased to approximately 190,000 net acres (from about 53,000 net acres two years prior) with excellent positions accumulated in a half-dozen, highly prospective areas in northeast B.C. and northern Alberta.
- Developed drill-ready exploration and development prospects at: Columbia, Edson, Ells/Birch Tar and Rainbow, Alberta; Umbach, Silver, and Ootla, British Columbia; and Minton, Weyburn, Saskatchewan, and brought on production from lower risk projects at Griffin, Saskatchewan; and in early 2003 at Sturgeon, Edson and Rainbow, Alberta.
- Advanced earlier-stage exploration projects at Tenaka and Maxhamish, BC and Turner Valley, Alberta, as well as continuing to advance long-term prospects in northeast BC.

Financial performance in 2002 was affected by volatile commodity prices. The year started with weak prices, followed by much improved prices for both oil and gas in the spring, then much lower Alberta gas prices in the summer, ending the year with robust crude oil prices and much higher gas prices heading into the winter. These factors came together with Purcell's success in developing crude oil projects, a decrease in natural gas production rates from Fort Liard and the early stages of investment for many additional oil and gas prospect areas that the Company is building.

The largest impact on Purcell in 2002 was from constrained gas production at Fort Liard caused by field operating issues. Last year we had forecast an average production rate of 6,000 BOE per day for 2002, which had assumed modestly declining production from Fort Liard and growing contributions from numerous other project areas. Even with new production from Minton and Griffin, Saskatchewan and Rainbow, Alberta, Fort Liard was, and continues to remain, a major portion of the production base of the Company. This area's reduced rates through most of 2002 affected the Company's total production average by about 1,000 BOE per day, but the development activity will turn Fort Liard performance positive in 2003.

Activity in 2002 was maintained at an aggressive pace with $38 million invested. Exploration and development progress was realized in many areas:

- At Fort Liard, the next phase of development was announced and is underway in early 2003. The operator drilled a second, directional well from the K-29 well site, enabling an increase in production of the gas field. The new well is expected to start production in the second quarter and, along with extensive modifications to the water-handling capacity, will support a return to higher production levels for the property.
- At Umbach, B.C., drilling of a well targeting Slave Point gas has helped to refine the play concept. Further land purchases and additional three dimensional seismic continue to develop the play and will result in the drilling of a second well in the summer of 2003.
- At Ootla, B.C., several shallow gas targets were drilled unsuccessfully and this project is currently under review. Drilling is underway on the Silver (formerly Slave) Slave Point gas prospect in northeast British Columbia. Results are expected in April 2003. Both areas required a lengthy lead-time to analyse the potential and assemble land positions.
- At Rainbow Lake, Alberta, Purcell has established a 500-BOE-per-day production base that will be further developed with additional drilling targeting gas and oil. The Purcell owned facilities and infrastructure enhance the economics of other Company prospects in the vicinity.
- Peco, Alberta is the site of a horizontal tight-gas play that still might establish commercial production rates.
- At Edson, Alberta, a successful gas well was drilled and will be placed on production in the second quarter of 2003, leading to additional drilling in 2003.
- At Minton, Saskatchewan, Purcell is continuing to develop its successful Winnipegosis and Red River oil pool. Potential exists to add production with productivity achievable per well of 200 barrels per day. The play also has potential to be extended north of Minton.

POSITIONED TO REALIZE GROWTH OPPORTUNITY

Purcell is constantly focused on its exploration portfolio. Progressing those opportunities requires capital investment, realizing that it can be anywhere from two to five years before the investments pay off. For a junior company, the challenge is to raise substantial capital that is then tied up for many years. Fort Liard is an excellent example as a project that is a "company-maker", yet required almost ten years to bring to fruition and $35 million in capital from a company that was generating annual cash flow of less than $2 million during its early years. One of Purcell's significant achievements has been financing its growth through a mix of debt and equity designed to keep share dilution to a minimum.

In 2002, Purcell's production slowdown at Fort Liard resulted in a shortfall in anticipated cash flow. Going into the year, the production base and growth plans supported a budget that assumed $23 million in cash flow. However, the water-handling difficulties at Fort Liard reduced the gas sales volumes, pushing daily production below expectations down to 4,022 BOE per day. The effect was cash flow of $14.7 million for the year. The challenge for Purcell was to continue to fund a planned $35 million program so that the numerous, quality exploration prospects could be advanced to the drilling stage in 2003 and beyond.

Purcell augmented its cash flow with equity and debt financings during 2002, as well as utilizing bank debt under its $35 million credit facility. The debt financing was a $5.0 million subordinate debenture closed in October and a flow-through share issue raised $6.2 million in December. Subsequent to year-end, a common share issue raised $2.9 million.

Another tactic Purcell uses to fuel its growth and manage risks is to enter into exploration partnerships with major producing companies designed to share the costs of early-stage exploration, as well as accessing regional expertise. Purcell works with Talisman Energy in the Fort Liard area. The companies are well positioned for land sales anticipated in late 2003 or early 2004. More recently, a joint venture with Anadarko Canada Corporation was formed to accelerate the exploration of the Tenaka area of northeast B.C. Both of these partnerships will allow Purcell to accelerate its activity in these areas, but will limit the risk exposure where drilling costs are often more than $2.5 million per well.

The Talisman partnership has resulted in the shooting and interpretation of 160 kilometres of seismic leading to the identification of several prospects. This exploration effort is important as it has prepared the groundwork for participating in land sales which have been anticipated for some time for the southwest Northwest Territories but may occur as early as the end of 2003. Purcell sees significant opportunities to drill more wells of similar calibre to the Fort Liard K-29 well. In winter 2003, under the Anadarko Tenaka joint venture, a 120 square kilometre, 3D seismic acquisition program was completed. Purcell covered 25 percent of the cost. Purcell has the option of participating in drilling the first exploratory well for 25 percent of the cost in order to retain a 37.4 percent working interest.

With the development program underway at Fort Liard, the range and number of drill-ready exploration prospects and the potential from quality partnerships, Purcell is in the best position in its 10-year history to substantially increase its reserves through the drill-bit and establish a diverse, high-quality, growing production base.

BUILDING THE TECHNICAL TEAM

Purcell's exploration focus is attractive to senior, technical explorationists, particularly in an environment where much of the capital expenditure activity in the industry is being directed by the risk-averse royalty trusts. The Company was able to add to its technical team during 2002 with highly qualified people. In early 2003 John Kuhn, P. Geol., joined the Company in the exploration group as Senior Geologist. John is working with Senior Geologist Keith Schneberger, P. Geol., who has been with Purcell since 2000. Keith and John support Rick Fedoruk, P. Geol., Vice President of Exploration, who has guided the Company's exploration strategy since 1998. Victoria Schut, Chief Geophysicist, Dave Klepacki, Consulting Geophysicist, and Carol Laws, Consulting Geophysicist provide expertise in geophysics.

Further depth was added in engineering. John Emery, P. Eng., joined Purcell as Senior Exploitation Engineer. In early 2003 Don Johnson, C.E.T., was appointed to the position of Production Supervisor. John and Don support Lawrence Backmeyer, P. Eng., Vice President of Engineering, who also has been with Purcell since 1998.

Purcell is well positioned to accelerate its activity in an environment that is energetic and enthusiastic. All of the members of the Company's technical staff have extensive experience, and in most cases well over 20 years' experience.

OUTLOOK FOR 2003

The outlook for 2003 has to take two major influences into consideration: the 2002 shortfall in production and currently high commodity price levels. Purcell entered 2003 with the objective of restoring Fort Liard production levels for the second half of the year and a realistic expectation for adding new production from the drilling activity that has occurred and is extending beyond the 2002/2003 winter drilling season. With a fourth quarter average production rate of 3,745 BOE per day, Purcell anticipates an average production rate for 2003 of 5,200 BOE per day. This growth will come from Fort Liard where production is expected to ramp up during the second quarter, from additional production that has been drilled and is awaiting tie-in or is already on production, and from development wells at Weyburn and Griffin in Saskatchewan. The variables that will influence meeting our targets include:

- The production capability of the 2K-29 development well and the effectiveness of the facility modifications at Fort Liard
- The timing of increased production at Fort Liard, Rainbow and Ells/Birch Tar
- The actual stabilized production rates for new wells placed on production
- The results of low-risk development drilling at Weyburn, Griffin and Minton

The high level of activity that has led to investments of $97 million over the last three years will be followed by a capital budget of $25 to $30 million for 2003. A reflection of the stage of Purcell's exploration activity is the increased spending in the drilling category for 2003 whereas land and seismic were major spending areas over the past two years. This increased drilling activity should lead directly to an impact on production and reserves in 2003 compared to results from the earlier phase of exploration that dominated 2002 efforts.

The pricing assumptions for 2003 for the Company's forecasts are CDN$6.00 per mcf for natural gas at AECO and US$25 (WTI) per barrel for oil. This pricing assumption has already been exceeded so far in 2003 and the outlook for gas, while uncertain, shows every indication of being sustained at these higher levels. Purcell's prices are also influenced by a hedging contract that covers 12,000 GJ per day until October 31, 2003 with a costless collar between CDN$4.00 to CDN$6.00 per mcf, and 7,000 GJ per day from November 2003 to April 2004 with a costless collar between CDN$6.83 to CDN$8.93 per mcf. It is anticipated that natural gas prices will remain strong through 2003 with natural gas storage reduced because of the unusually cold winter in the eastern regions of North America. For crude oil prices, the premium relates to the conflict in Iraq, tensions throughout the Middle East and the on-going political difficulties in Venezuela. However, these political situations are difficult to predict in terms of the impact on oil prices over the medium and longer term.

I would like to extend my appreciation to Purcell's independent directors and all of our supporters, and most especially, our dedicated employees, who have contributed to the Company's development.

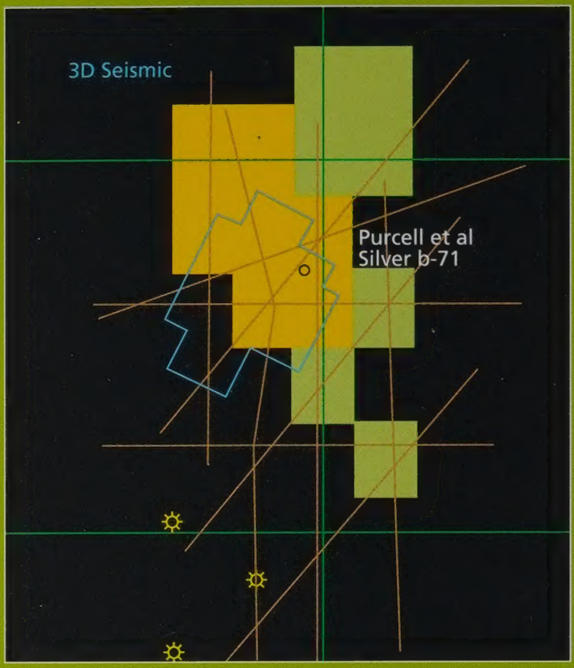
On behalf of the Board,

Jan Alston, President and CEO
March 27, 2003

WHAT'S IN A NAME?

ACHO DENE KOE IS THE FIRST NATIONS BAND RESIDENT IN AND AROUND THE FORT LIARD AREA. THE BAND AND THE SCHOOL ESTABLISHED A LITERACY PROGRAM TO IMPROVE ENGLISH WRITING AND READING SKILLS TO OPEN UP EDUCATIONAL AND CAREER OPPORTUNITIES FOR BAND MEMBERS. PURCELL HAS CONTRIBUTED FINANCIALLY TO THE PROGRAM, IN EACH OF THE PAST THREE YEARS. APPRECIATIVE OF THE SUPPORT, CHILDREN OF THE ACHO DENE ELEMENTARY SCHOOL PRESENTED PURCELL WITH A HEARTFELT "THANK YOU" IN A CHRISTMAS CARD.

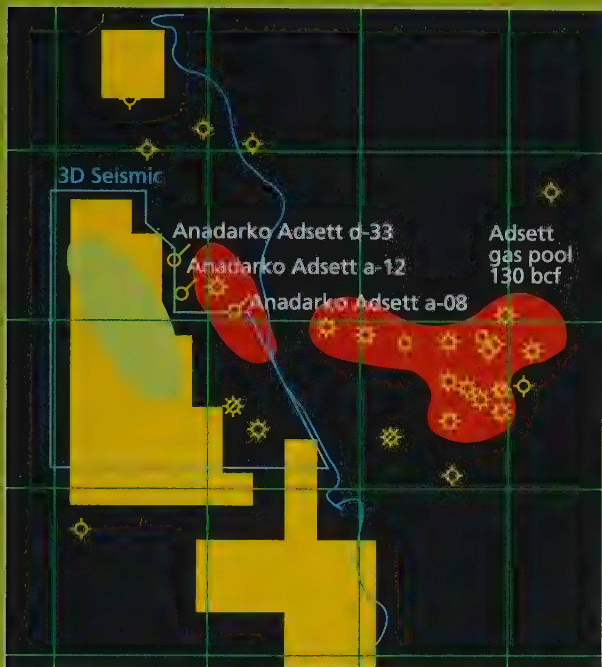
Purcell has had a two-year process of reinvesting its growing capital into a range of exploration areas offering high-impact prospects extending from northeast British Columbia to Minton, Saskatchewan. The prospect development represents investment in seismic, land and drilling as well as successful negotiation of participation agreements to accelerate activity and increase resources for specific projects. The combined impact of the last 18 to 24 months of activity is to have positioned Purcell with a top quality basket of opportunities rivalling anything assembled by other junior oil and gas companies.



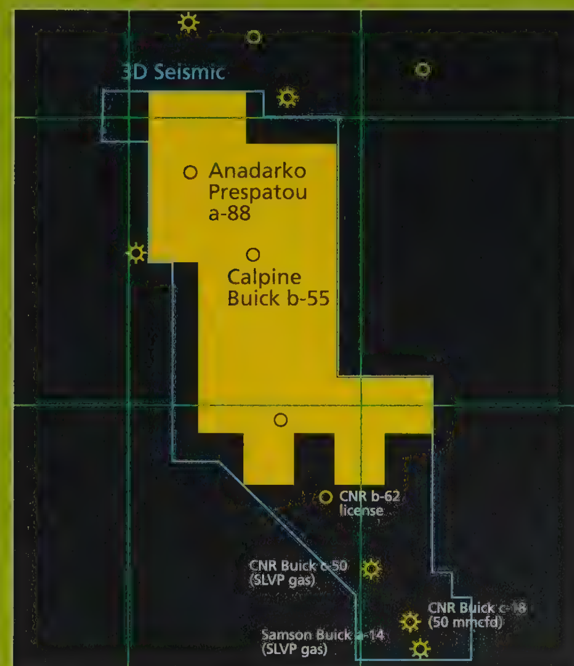
IN 2002, PURCELL'S ACTIVITY LEVEL REACHED NEW HEIGHTS FOR THE COMPANY AS IT UNDERTOOK THE MOST DIVERSE PROGRAM IN ITS HISTORY, WITH A FULL RANGE OF EXPLORATION AND DEVELOPMENT PROGRAMS IN A NUMBER OF PROJECT AREAS.

AREA	LAND GROSS (NET) ACRES	2002 PRODUCTION	2001 PRODUCTION	2002 CAPITAL INVESTED ($000)
NORTHWEST TERRITORIES				
Fort Liard (24% to 60% interest)	13,575 (3,546)	15.79 mmcf/d	21.47 mmcf/d	115
British Columbia	160,993 (96,456)			
Ootla (100% interest)	17,632 (under option)			613
Silver (formerly Slave) (25% interest)	9,698 (under option)			549
Tenaka (63% interest before farmout and 37.4% interest after farmout)	40,358 (25,657)			643
Umbach/Buick Creek (4% and 25% interest)	13,863 (3,466)			3,060
Kiwigana, Maxhamish, Petitot and other	106,772 (67,333)			2,012

TENAKA

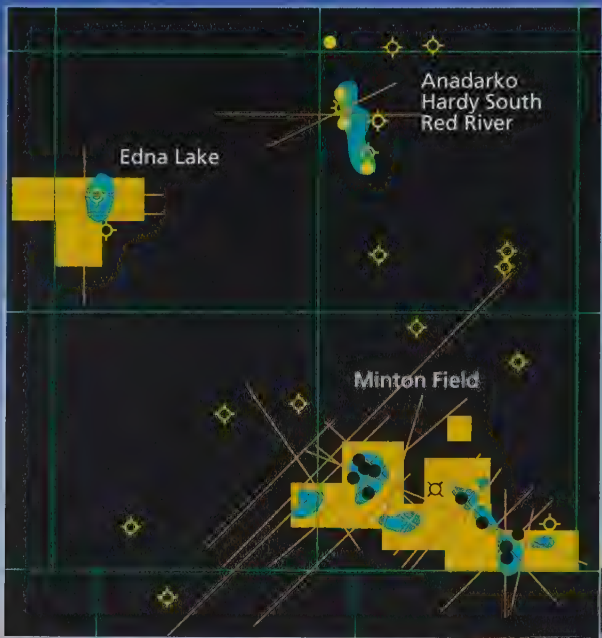


UMBACH



2002 PROGRAM	2003 PLANS
Maintenance; production reduced (water-handling limits); Operator's comprehensive development plan approved	Drilled 2K-29 directional well in Q1, completion and tie-in to existing K-29 facility in Q2; facilities upgrade to increase water-handling capacity; possibility of another development well later in the year
Shot 2D seismic and interpreted	Drilled 4 separate shallow gas prospects (100%); Project on hold pending review of results
Shot 3D seismic and interpreted	Exploration well spudded in March (50% before payout; 25% after payout) to earn in 4,700 acres; 50% partner reimburses 50% cost of seismic
Investment in land and 2D seismic purchases; seismic interpretation	Interpretation of a 120 square kilometer 3D seismic program completed in Q1 over 23 gas spacing units included in the Anadarko joint venture will set up drill targets for next winter; Interpret 2D data over another 37 gas spacing units
In Q3 drilled exploration well (50% to earn 25%) on 3D seismic; purchased four contiguous gas spacing units	Shot additional 3D seismic and purchased two contiguous gas spacing units in Q1; complete interpretation of 3D; plan to drill a second exploratory test in Q3; several prospects on Company lands
Implemented a land posting strategy in northeast B.C. based on early stage exploration; acquired lands and purchased copies of 2D seismic	Interpret seismic data and continue land acquisitions; seek partners in new joint ventures where appropriate

MINTON



RAINBOW

AREA	LAND GROSS (NET) ACRES	2002 PRODUCTION	2001 PRODUCTION	2002 CAPITAL INVESTED ($000)
ALBERTA	331,627 (94,768)	3.72 mmcf/d 247 bbls/d	2.89 mmcf/d 166 bbls/d	
Columbia	3,200 (under option)			
Edson/Pine Creek	5,440 (2,672)	0.73 mmcf/d 6 bbls/d	0.72 mmcf/d 9 bbls/d	1,746
Ells/Birch Tar (10 to 19% interest)	213,108 (32,284)	1.3 mmcf/d	1.01 mmcf/d	1,404
Peco (22.5% interest)	10,569 (3,275)			1,623
Rainbow (50 to 100% interest)	15,680 (12,668)	0.45 mmcf/d 86 bbls/d		17,109
Monitor, Wainwright, and other	26,070 (9,811)	1.31 mmcf/d 155 bbls/d	1.16 mmcf/d 157 bbls/d	5,116
SASKATCHEWAN	19,243 (16,891)	515 bbls/d	361 bbls/d	
Griffin (42% interest)	160 (56)	59 bbls/d		254
Minton (100% interest)	10,324 (10,324)	304 bbls/d	202 bbls/d	2,160
Weyburn/Tatagwa	1,808 (1,304)	92 bbls/d	95 bbls/d	371
Other minor	6,835 (5,094)	60 bbls/d	64 bbls/d	869

2002 PROGRAM	2003 PLANS
	Farm-in negotiated in Q1; exploration well planned for Q2
Drilled 60% gas well; acquired additional lands	Tied in well in Q1; exploration well planned for Q3
Increased interest in both areas; drill development wells at Birch Tar	Tie-in wells; drill exploration and development wells in Q1
Acquired lands; drilled horizontal gas well (22.5%); stimulated vertical well	Complete gas well and stimulate horizontal drilled; evaluate results
Significant up front investment to bring infrastructure into a new area; constructed a battery and a nine-mile 6" sour gas pipeline with compression; brought three wells onstream	Gas well tie-in completed in Q1; development gas well planned for Q3 based on 2D seismic shot in Q1; further development locations and other prospects to be moved forward
Purchased lands on Turner Valley exploratory gas play and other deep gas southern Alberta plays	Advance technical work on prospect
Drilled a horizontal oil well placed on production in August	In Q1 acquired lands; planning to drill an oil development horizontal well in Q2
Produced development well drilled in 2001; granted permission to co-mingle two zones	Plan to drill an oil development well; developing an exploratory Winnipegosis oil target at Edna Lake north of Minton property
Drilled development horizontal oil well in Q4	Completing horizontal for oil production after spring break up in Q2; development drilling in Q3

WHAT'S IN A NAME?

FORT LIARD IS AN AREA OF STRIKINGLY BEAUTIFUL AND RUGGED MOUNTAINOUS TERRAIN. IT IS ALSO THE SITE OF INFAMOUS LEGENDS ABOUT MURDER AND GOLD-PROSPECTING FROM THE EARLY 1900S THAT RESULTED IN THE NAMES OF LOCAL AREAS SUCH AS "GOLD CREEK" AND "DEADMEN VALLEY." PERHAPS A MOST APPROPRIATE AREA FOR A "COMPANY-MAKER" PLAY.

MAJOR PROJECTS

FORT LIARD, NORTHWEST TERRITORIES

Profile

Fort Liard continues to be a very successful project for Purcell. This area has not disappointed in any fundamental way. The reserve estimates remain intact despite the constrained gas production rates in 2002. The reason? The lower production rates were caused by lack of capacity to handle increased water produced along with the natural gas. Excellent pressure build up data taken during the annual Fort Nelson plant turnaround over several years provides strong confirmation of the reserves. Production during 2002 averaged 15.8 mmcf per day net to Purcell from its interests in three producing wells. Development plans are aimed at restoring production levels and the opportunity for exploration will follow participation in the next land sale.

2002 - Development Plan Approved for 2003

During 2002, Purcell and its partners detailed and approved a development program for Fort Liard that is expected to significantly improve production management. In January and February 2003, the 2K-29 directional well was drilled from the original K-29 well site (24 percent working interest), designed to support gas recovery from the pool. It is expected that the new well will be tied in and producing through the existing K-29 facility by the end of April 2003. In addition, investment in the on-site facilities will increase capacity so that the water produced with the natural gas can be managed, reducing the need to limit production rates. It is expected that the production rate for M-25 can now be increased above the previously constrained rates. The quality of the reservoir is indicated by the fact that the K-29 well still produces at rates exceeding 40 mmcf per day of raw gas, a full 35 months after it was placed on stream. These are long-life reserves and investments in the production facilities and further drilling will improve the ability to recover these reserves.

The M-25 well site offers the opportunity to produce from the upper portion of the Nahanni zone that is behind casing. Depending on the production history of the well, this remedial work could take place in 2003. The M-25 well (24 percent working interest) produced an average of 20.6 mmcf sales gas per day in 2002 compared to 47.6 mmcf per day in 2001. A strategy consistent with drilling the 2K-29 development well is to drill another development well on the south structure from the M-25 location to maximize usage of facilities. This may occur before the end of 2003.

NORTHWEST TERRITORIES EXPLORATION

Extensive exploration activity

Purcell has conducted extensive exploration activity in the greater Fort Liard region under its Talisman Energy Inc. joint venture, in order to identify prospects that might offer a natural gas pool that rivals the Liard field. With this work complete, timing of additional activity depends on a land sale that may be announced as early as the end of 2003. An Interim Resource Development Agreement between the Deh Cho First Nation and the federal government is to be signed in April 2003. The last land sale in the southern Northwest Territories occurred in 1996.

DEVELOPING PROSPECTS IN NORTHERN B.C. AND NORTHERN ALBERTA

Profile

Most of Purcell's reinvestment over 2001 and 2002 has been directed to building prospects in high-impact areas in northeast British Columbia and northern Alberta. These investments have generated substantial progress with drilling and development activity underway and escalating through 2003. Many of these areas should begin to have a notable impact on reserves, production and cash flow in 2003.

Kiwigana, B.C. Purcell (33 percent interest) has assembled approximately 29,000 gross acres on this shallow gas play in northeast B.C. Three wells licensed for drilling this winter were deferred by the operator. Drilling is expected in early 2004. Deeper gas potential also exists on this acreage.

Tenaka, B.C. Over the past two years, Purcell assembled a large block of land west of the Adsett Slave Point gas pool in northeast B.C. with published recoverable gas reserves of 130 BCF. The Company has an average 63 percent interest in approximately 42,000 acres. A farmout and joint venture agreement was negotiated with Anadarko Canada Corporation covering approximately 50 percent of Purcell's landholdings at Tenaka. Purcell has interests in 59 gas spacing units immediately west of Anadarko's Adsett gas pool. The joint venture will cover approximately 23 gas spacing units on the northern part of the Company's acreage. 2D seismic data interpreted by Purcell has identified multiple Slave

Point prospects. Pursuant to the joint venture, a 120 square kilometer 3D seismic program was conducted in the first quarter of 2003. Purcell will pay 25 percent of the $4.6 million cost of the program. Anadarko has the option to elect to drill a Slave Point test on the joint venture lands next winter, with Purcell having the right to participate for 25 percent. In the event a well is drilled and Purcell participates, Purcell will retain a 37.4 percent working interest in the joint venture lands. Under the agreement, gas produced from the joint venture lands will be processed through Anadarko's existing Adsett infrastructure.

Umbach, (Buick Creek) B.C. An extensive 3D seismic program was conducted in April 2002 and a well was drilled in September 2002 (50 percent interest before payout and 25 percent after payout). With more seismic shot in the 2002/2003 winter season, a second Slave Point well is planned for later in the second quarter. Purcell has 4,055 net acres in this project.

Silver (Slave), B.C. Purcell has an option to earn an interest in up to 14 sections on this Slave Point gas play in northeast B.C. A significant 3D seismic program was conducted over the acreage in winter 2002/2003. The Silver well was begun in March 2003 (50 percent working interest). The structure shows potential for substantial gas reserves.

Columbia, Alberta. An exploration gas prospect will be drilled in 2003, for a 50 percent working interest. The play is targeting the Viking zones.

Edson/Pine Creek, Alberta. Expanding on the Pine Creek area exploration, a 60-percent-interest well was drilled in Edson in July 2002 and was completed as a gas well in the fourth quarter of 2002 and is expected to be tied-in during April of 2003. The Company has other prospects on its lands and plans to drill a well in 2003.

Rainbow, Alberta. Development of this gas and oil project is underway. Five wells were drilled on this project in 2001 and early 2002. The Company constructed a nine-mile gathering pipeline for sour gas and an oil battery. The wells were tied in during 2002. Production is expected to exceed 500 BOE per day net to Purcell for 2003. The Company is planning to drill a well (50 percent interest) in the third quarter of 2003.

SASKATCHEWAN: A DEEP PROSPECT, GROWTH AREA

Profile

Saskatchewan is the site of Purcell's traditional area of operations. The Company's projects have shifted focus to deeper, higher quality reserves; plays that are supported by more recent technology for analysis and drilling. Over the past two decades, a handful of companies have pursued deep prospects like the Winnipegosis geologic zone. Purcell's drilling for this zone over the past two years has resulted in success and the project-type continues to be developed.

Minton. This 100-percent-Purcell play has been one of the most successful programs targeting the 2,500-metre deep Winnipegosis zone. Through 2002, the initial well averaged 150 bbls per day of light crude oil production. At year end, Purcell received permission to co-mingle the Red River zone with the Winnipegosis and the result should be an average of 175 bbls per day through 2003. Total property production in 2003 is forecast to be about 250 bbls per day of light oil. Additional plans include a development well in 2003 and a test well to the northwest on an exploration prospect at Edna Lake.

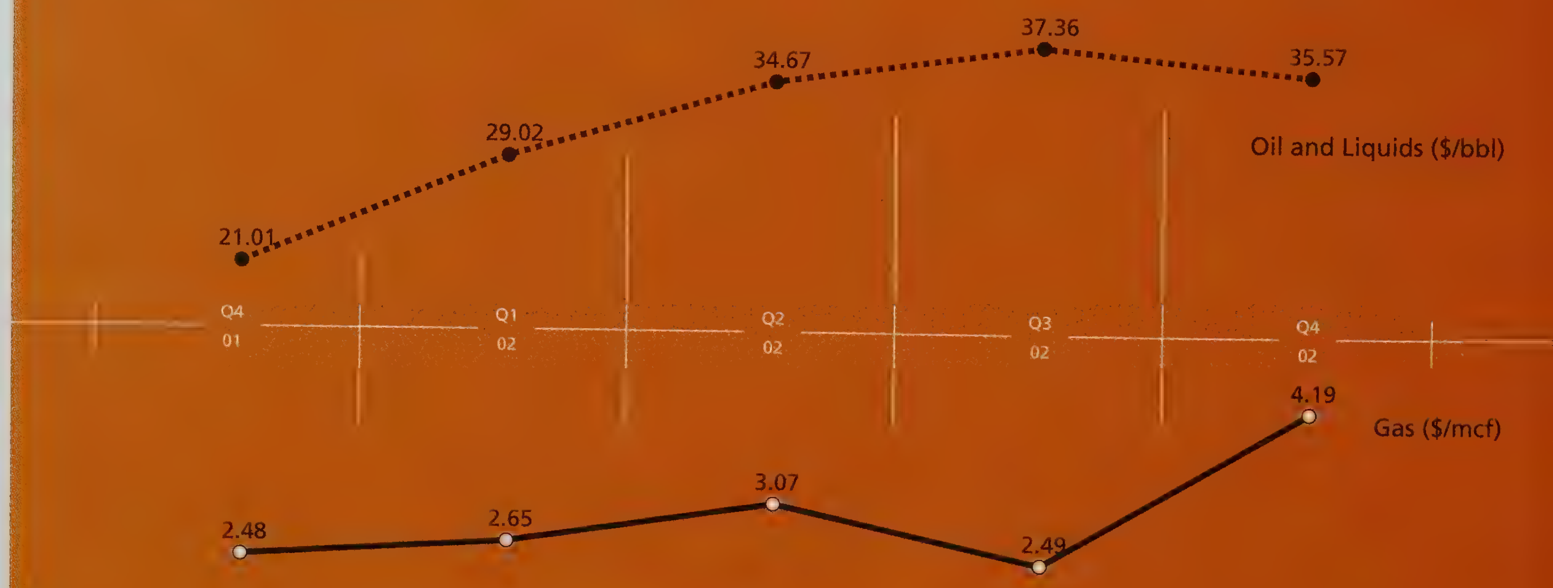
WHAT'S IN A NAME?

FISH: EXPLORATION SLANG INCLUDES MENTION OF DOGS AND FISH, SUCH AS THE "DOGHOUSE" USED ON THE DRILLING SITE OR "FISH" REFERRING TO ANY OBJECT ACCIDENTALLY LOST IN THE WELLBORE THAT MUST BE REMOVED BEFORE DRILLING CAN CONTINUE.

IN 2002, PURCELL CONTINUED ITS PROGRAM OF STEPPED-UP REINVESTMENT INTO EXPLORATION PROJECTS THAT SPAN FROM THE NORTHWEST TERRITORIES THROUGH TO SOUTHEAST SASKATCHEWAN WITH A SIGNIFICANT FOCUS ON HIGH-IMPACT AREAS IN NORTHEAST BC AND NORTHWEST ALBERTA. THE IMPACT OF THIS SPENDING IN 2002 WAS A SIGNIFICANT INCREASE IN UNDEVELOPED LAND HOLDINGS, TO 189,552 NET ACRES, AND AN EXTENSIVE LIST OF QUALITY DRILLING LOCATIONS TO FOLLOW 2002 EXPLORATION DRILLING. AS WITH ALL EXPLORATION ACTIVITY, THERE IS INHERENT RISK. HOWEVER, PURCELL'S RANGE OF PROSPECTS AND PLAY-TYPES SHOULD DIVERSIFY THE RISK AND LEAD TO MEANINGFUL GROWTH IN RESERVES AND PRODUCTION BY YEAR-END 2003 AND THEREAFTER. ADDED TO THE OPTIMISM FOR 2003 IS A WIDELY HELD CONSENSUS THAT NATURAL GAS PRICES WILL REMAIN STRONG THROUGH THE YEAR.

FOR THE PURPOSES OF CALCULATING UNIT COSTS, NATURAL GAS IS CONVERTED TO A BARREL EQUIVALENT ("BOE") USING SIX THOUSAND CUBIC FEET EQUAL TO ONE BARREL. BOE IS A MEASURE THAT PROVIDES AN APPROXIMATE COMPARISON BUT CAN BE MISLEADING, PARTICULARLY IF USED IN ISOLATION.

Commodity Prices (Wellhead)



2002 SUMMARY

- 2002 average production of 4,022 BOE per day was down from 2001 production of 4,604 BOE per day as a result of reduced production at Fort Liard caused by increased water production combined with the physical limits of the area's facilities to handle the volume. Activity in 2003 will address the facilities limitation and allow production to be increased.
- Reserves at Fort Liard remained basically unchanged, after allowing for production in 2002, indicating that the Fort Liard reserves are solid. Total proved and probable reserves at the Company's other properties increased by 19 percent after taking into account 2002 production.
- Revenue of $26.7 million in 2002 decreased from $30.4 million in 2001, directly reflecting the reduced production rates at Fort Liard and increased royalties with natural gas prices only increasing late in the year.
- Cash flow of $14.7 million ($0.544 per share, diluted) was 29 percent (31 percent on a per share basis) lower than 2001.
- Net capital expenditures of $35.2 million, down five percent from $37.1 million in 2001, were funded by cash flow, additional bank and long-term debt (bringing the outstanding debt balance to $35.7 million) and equity issues that generated $6.2 million.

RESULTS OF OPERATIONS

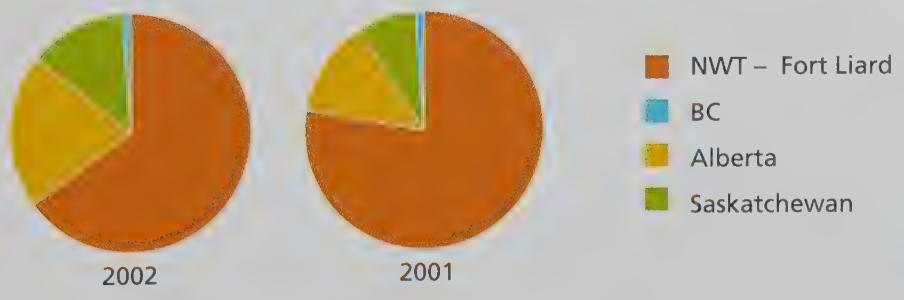
Revenue

Revenue of $26.7 million in 2002 was down 12 percent from $30.4 million in 2001 reflecting a reduction of 13 percent in equivalent production and a four percent reduction in sales prices received per BOE. Crude oil production increased by 45 percent to 763 barrels per day, however over 80 percent of Purcell's production is natural gas and that fell by 20 percent to 19.56 mmcf per day for the year. The reduction in natural gas production related to increased water production at the M-25 well at Fort Liard with on-site facilities unable to handle the increase, resulting in reduced gas production. Crude oil additions were recorded at Griffin, Saskatchewan and Rainbow, Alberta, the result of successful drilling in 2002.

Commodity prices received during 2002 reflect a 14 percent drop in the average gas price to $3.06 per mcf compared to $3.57 in 2001 and a 19 percent increase in crude oil and liquids prices averaging $34.56 per barrel compared to $29.02 a year earlier. As a result of price hedging in 2002, prices received were four percent higher for natural gas and three percent lower for crude oil compared to average spot prices. In the fourth quarter of 2002 hedging reduced natural gas prices received by 5.6 percent and reduced crude oil prices received by 3.2 percent.

A shift in fundamentals was evident in the fourth quarter with a 69 percent increase in natural gas prices received at the well head, to $4.19 per mcf compared to $2.48 per mcf in the same period of 2001. Crude oil and liquids prices remained strong, increasing by 69 percent to $35.57 compared to $21.01 per barrel. Fourth quarter production continued the same trend, with natural gas down by 36 percent compared to the year earlier as a result of reduced production at Fort Liard partially offset by new production in Alberta at Crossfield and Rainbow. Liquids production was up 40 percent in the fourth quarter to 864 barrels per day compared to the fourth quarter of 2001 as a result of new production at Griffin and Minton, Saskatchewan offset by normal production declines at other areas.

Production Diversification



Production by Area

(BOE = 6 mcf equal to 1 bbl)	2002 Natural Gas (mmcf/d)	2002 Crude oil & liquids (bbls/d)	2002 BOE/d	2001 Natural Gas (mmcf/d)	2001 Crude oil & liquids (bbls/d)	2001 BOE/d
NWT - Fort Liard - F-25A	3.29	-	549	2.39	-	398
- K-29	7.56	-	1,259	8.39	-	1,398
- M-25	4.94	-	823	10.69	-	1,781
Total NWT	15.79	-	2,631	21.47	-	3,577
British Columbia	0.05	1	10	0.10	1	19
Alberta						
- Ells/Birch Tar	1.23	-	205	1.01	-	168
- Monitor	0.51	5	90	0.71	4	122
- Pine Creek	0.73	6	128	0.72	9	128
- Rainbow	0.45	86	162	-	-	-
- Wainwright	0.04	118	124	0.09	114	128
- Other	0.76	32	157	0.36	39	101
Total Alberta	3.72	247	866	2.89	166	647
Saskatchewan						
- Griffin	-	59	59	-	-	-
- Minton	-	304	304	-	202	202
- Rapdan	-	60	60	-	63	63
- Weyburn/Tatagwa	-	92	92	-	95	95
- Other	-	-	-	-	1	1
Total Saskatchewan	-	515	515	-	361	361
Total Purcell	19.56	763	4,022	24.46	528	4,604

Revenue Impact

($ thousands)	Crude oil	Natural gas	Total
2001 Revenue, before royalties	5,593	26,879	32,472
Increase (decrease) due to:			
Price	1,731	(697)	1,034
Volume	2,321	(5,688)	(3,367)
Acquisitions	228	379	607
2002 Revenue, before royalties	9,873	20,873	30,746

Sales by Product (Wellhead)

($ thousands)	**2002**	2001
Crude oil and liquids	**9,873**	5,593
Natural gas	**20,873**	31,879
Total	**30,746**	37,472
Average price ($/BOE, excluding hedging)	**20.94**	22.29

Expenses

Increased expenses relate to the higher level of activity in all areas. Costs are increasing throughout the industry. Purcell's increased activity level has also necessitated the addition of technical staff.

Royalty expenses increased in 2002 as a result of Crown royalties increasing to an average of $3.07 per BOE, up 157 percent over the $1.19 per BOE average in 2001. The main reason for this increase was higher frontier royalty rates after reaching payout of costs at Fort Liard in early 2002. Capital expenditures at Fort Liard in 2003 will lower royalties until payout of these additional costs. Crown royalties in Alberta and Saskatchewan were up by 19 percent due to increased oil revenues. Alberta royalty tax credits increased by 23 percent in 2002 to $252,000 in conjunction with higher royalties paid in Alberta. Royalty expenses increased by 592 percent in the fourth quarter of 2002 to $2,071,025 compared to the same period in 2001 as a result of the increased Fort Liard royalties and higher revenues resulting from significantly higher commodity prices.

Royalty (Crown, Freehold and Overrides) Expenses by Product

($ thousands)	2002	2001
Crude oil and liquids	**1,450**	1,059
Natural gas	**3,773**	1,434
	5,223	2,493
Average cost ($/BOE)	**3.56**	1.48
Percentage of sales (%)	**17.0**	6.7

Production expenses increased 23 percent to $7.9 million from $6.4 million in 2001. The increase relates to generally more expensive industry costs but also reflects the higher cost remote areas where Purcell is active. Operating costs per BOE at Fort Liard increased in 2002 due to reduced production volumes. Operating expenses increased further per BOE in the fourth quarter of 2002 due to additional production constraints at Fort Liard. As the majority of processing and operating costs at Fort Liard are not variable, the restoration of production levels will result in a reduction of operating costs per unit in 2003. Operating costs per BOE in Alberta increased mainly due to start-up issues at Rainbow. Optimum production levels at Rainbow, originally anticipated in 2002, are expected to be reached in the second quarter of 2003. Higher oil production at Minton pushed operating costs per unit down in 2002.

Production Expenses by Area

		2002		2001
($ thousands)	Amount	$/BOE	Amount	$/BOE
Northwest Territories	**3,292**	**3.43**	3,317	2.54
British Columbia	**82**	**22.14**	31	4.50
Alberta	**2,882**	**9.11**	1,560	6.61
Saskatchewan	**1,624**	**8.65**	1,485	11.28
Total production expenses	**7,880**	**5.37**	6,393	3.80

WHAT'S IN A NAME?

WHIPSTOCK: THE EXPLORATION SIDE OF THE OIL BUSINESS IS FILLED WITH SLANG SUCH AS "WHIPSTOCKING" WHICH REFERS TO A LONG STEEL WEDGE USED TO DEFLECT THE BIT FROM THE ORIGINAL BOREHOLE IN ORDER TO DIRECTIONALLY DRILL OR STRAIGHTEN CROOKED HOLES.

General and administrative costs, before capitalization and recoveries, increased by nine percent to $3.6 million in 2002 due to higher personnel and occupancy costs. The Company continues to add expertise to manage and exploit its growing asset base. Net general and administrative (G&A) expenses increased by 24 percent to $1.49 per BOE in 2002 reflecting the reduced production volumes. G&A expenses in the fourth quarter were 44 percent lower than 2001 after the set up of the deferred pension asset. Before the pension adjustment, G&A expenses were up 10 percent in the fourth quarter. In 2002 Purcell capitalized $867,000 of G&A expenses related to exploration activities compared to $702,000 in 2001. This increase reflects the higher cost levels in 2002. G&A expenses recovered, as part of the process of the Company operating capital projects and producing wells, reduced by seven percent to $501,000 in 2002. Net G&A expenses in 2003 are expected to be around $2.5 million.

General and Administrative Expenses

($ thousands)	2002	2001
Personnel costs	2,130	1,904
Rent and occupancy costs	314	237
Other	1,119	1,123
	3,563	3,264
Capitalized expenses	(867)	(702)
Recoveries	(501)	(538)
Net general and administrative costs	2,195	2,024

Depletion and site restoration costs increased by 23 percent in 2002 to $12.6 million representing a 41 percent increase to $8.59 per produced BOE. Significantly higher finding and development costs have driven depletion costs upwards in 2002. The Company experienced limited exploration success in 2002 with net proved and probable reserve additions replacing 73 percent of production. Depletion and site restoration in the fourth quarter of 2002 decreased by two percent compared to the same period last year as a result of 27 percent lower production levels offsetting the higher finding and development costs. Depletion and site restoration costs in 2003 will likely increase to around $10 per produced BOE as a result of the higher costs. Despite the higher costs, higher commodity prices pushed the ceiling test cushion to $83 million at December 31, 2002 from $17 million a year ago. The ceiling test cushion is the excess of the undiscounted, after tax, unescalated proved reserves value over the cost balance of the petroleum and natural gas assets recorded on the balance sheet.

Interest expense increased by 48 percent in 2002 to $1.4 million and fourth quarter interest expense of $0.6 million is up 99 percent over 2001 reflecting higher outstanding bank loan balances and the $5.0 million subordinate debenture financing completed in October 2002. Debt levels were increased to support the extensive capital program carried out by the Company in 2002. Interest expense is expected to increase to around $2.2 million in 2003 reflecting higher average loan balances and slightly higher average lending rates.

Income taxes

The Company is not currently taxable except for the federal large corporation's tax and Saskatchewan capital taxes. Tax pools, detailed in Note 10 to the consolidated financial statements, total $63 million at December 31, 2002 compared to $51 million at December 31, 2001. Included in the tax pools at December 31, 2002 are $1.2 million of successor costs that are deductible only against income earned from certain petroleum properties. Based on current capital expenditure plans, the Company is not expected to pay any cash income taxes in 2003.

Net Income and Cash Flow

Net income is down by 85 percent and cash flow is lower by 29 percent in 2002 as a result of 12 percent lower revenues and 23 percent higher operating expenses. Revenues were down to $26.7 million in 2002 due to a 13 percent reduction in equivalent

production combined with a four percent decline in commodity prices received per BOE. The fourth quarter resulted in a net loss of $0.18 million, down from a profit of $0.35 million in 2001. Cash flow in the fourth quarter increased eight percent reflecting revenues up 17 percent to $7.5 million offset by increased production expenses and interest costs. Fourth quarter revenues rose as a result of a 76 percent increase in product prices received per BOE offset be a 27 percent reduction in equivalent production. The reduction in Fort Liard production is the predominant reason for the decline in net income and cash flow in 2002. In 2003, additional production at Fort Liard, Rainbow and other areas is expected to contribute to a rise in net income to $5 million and an increase in cash flow from operations to $28 million.

Netback Analysis

($/BOE)	2002	2001
Revenue	21.55	19.44
Royalty expenses	3.39	1.36
Production expenses	5.37	3.80
General and administrative expenses	1.49	1.20
Financing charges	0.98	0.58
Capital taxes	0.32	0.17
Cash flow from operations	10.00	12.33
Depletion and depreciation	8.59	6.08
Future income taxes	0.67	1.84
Net income	0.74	4.41

Quarterly Summary

			2002				2001	
($000, unless otherwise indicated)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Production								
Natural gas (mcf/d)	17,281	17,112	19,575	24,363	29,960	28,270	21,410	21,086
Crude oil & NGL (bbls/d)	864	883	671	628	618	485	480	529
BOE/d	3,745	3,735	3,933	4,689	5,111	5,196	4,047	4,043
Sales Prices (1)								
Natural gas ($/mcf)	4.19	2.49	3.07	2.65	2.48	2.31	4.65	5.65
Crude oil & NGL ($/bbl)	35.57	37.36	34.67	29.02	21.01	32.77	32.26	30.73
Revenue, net	7,465	6,095	6,405	6,712	6,372	4,885	7,721	11,428
Cash flow	3,962	3,132	3,496	4,087	3,685	2,236	5,476	9,321
Capital expenditures (2)	6,131	8,651	10,526	9,924	9,282	9,057	8,830	9,924
Bank debt, end of period	30,703	34,844	32,906	25,570	20,000	19,346	14,762	11,356
Debenture, end of period	5,000	-	-	-	-	-	-	-
Share Trading								
High ($)	2.95	2.70	3.23	3.60	3.79	4.23	5.12	4.68
Low ($)	2.16	2.01	2.50	2.80	2.70	2.74	3.70	3.35
Close ($)	2.91	2.20	2.65	2.98	3.30	2.85	3.95	4.59
Volume (000 shares)	2,475	1,584	3,372	4,251	2,484	3,702	4,796	6,082

(1) Revenue and sales prices are net of transportation costs

(2) Capital expenditures are net of proceeds from dispositions.

Liquidity and Financial Resources

Not only is full-cycle exploration a less common growth strategy in the Canadian oil industry today, but it is especially unique for a junior company. The reason is that the capital needs are significant and the lead-times from investment to realized cash flow are also longer than for exploitation- or acquisition-based strategies. However, the quality and size of reserves that can be discovered reward the true exploration company, as evidenced by the Fort Liard project that transformed Purcell. Purcell's challenge has been to generate capital when needed in order to continue a high level of activity and reinvestment. Over the past three years, since Fort Liard has come on-stream, Purcell has invested a total of $97 million developing Fort Liard and other projects of which over $20 million were used specifically to build an inventory of exploration plays in a number of key areas of western Canada. Including that investment, $33 million were leveraged through bank debt and other debt instruments, $25 million were raised through equity issues and the balance was financed by cash flow.

At December 31, 2002, debt, including the working capital deficiency, totaled $40.2 million, up from $21.4 million at December 31, 2001. Year-end debt represents a debt-to-cash flow ratio of 2.73-to-1 on trailing cash flow and 2.53-to-1 on fourth quarter 2002 cash flow annualized. Debt is forecast to be slightly more conservative at the end of 2003 at $37 million. However, the debt-to-trailing cash flow ratio is expected to significantly improve to 1.30-to-1 as a result of increased cash flow from operations in 2003.

Capital Program

In 2002, Purcell maintained its high level of activity, investing $35 million (net of dispositions) up from the initial budget of $32 million. The capital program was funded 41 percent by cash flow, 17 percent by the issue of common shares and the remainder by debt and working capital.

Purcell continued to advance its full cycle exploration and development program in 2002 including the acquisition of an additional 115 net sections of undeveloped land in Alberta and British Columbia and the participation in drilling of 16 (6.3 net) wells. The number of wells drilled is small but the average footage drilled per well is substantially higher than the western Canadian industry average. This is consistent with Purcell's strategy of pursuing deep gas targets. In 2002, footage drilled averaged 5,030 feet per gross well (7,000 feet per net well) reflecting the deeper, higher risk/reward projects targeted by Purcell. The drilling program in 2002 resulted in a 66 percent success rate and modest reserve additions. While development programs expect successes eight or nine out of 10 attempts, true exploration expects a much lower success rate with one or two successes out of 10 attempts not unusual.

During 2002 Purcell spent $17.1 million, 49 percent of its capital program, in the Rainbow, Alberta area. Expenditures at Rainbow included the acquisition of $2.5 million of developed and undeveloped acreage, $4.7 million on drilling and completions and $9.9 million on a battery and sour gas pipeline. The Company decided to make a substantial investment in infrastructure in this area to support future exploration and development activities. The expenditure on the facilities will enable Purcell to bring reserves from any new prospects in the area on production without delay at lower cost.

The Company is continuing its capital program in 2003 with emphasis on the exploration of its inventory of full-cycle high risk/reward prospects. The Company's 2003 capital budget of $27 million is dedicated 70 percent to drilling, completion and tie-in activities. The Company's plans include drilling 29 gross (13 net) wells in 2003. The emphasis on exploration drilling in 2003 is similar to 2002 at about 50 percent of the capital program.

Capital Expenditures

($ millions)	Budget 2003	**2002**	2001
Undeveloped land	2.2	**3.4**	4.2
Geological and geophysical	3.5	**4.1**	6.9
Drilling and completions	18.5	**17.3**	18.5
Acquisitions (dispositions), net	0.8	**0.1**	(1.7)
Facilities and gathering systems	1.8	**10.2**	9.0
Other	0.2	**0.1**	0.2
Total	27.0	**35.2**	37.1

Capital Expenditures

Undeveloped Acreage

(acres, at December 31)	2002 Gross	2002 Net	2001 Gross	2001 Net
Alberta	**270,587**	**81,000**	197,660	43,111
Saskatchewan	**14,839**	**13,091**	32,931	13,896
British Columbia	**183,326**	**95,078**	113,772	58,744
Northwest Territories	**1,596**	**383**	1,596	383
Total	**470,348**	**189,552**	345,959	116,134

Drilling Activity

	2002 Gross	2002 Net	2001 Gross	2001 Net
Exploratory				
Gas	**3**	**0.98**	6	1.62
Oil	**1**	**1.00**	2	2.00
Dry	**5**	**1.12**	-	-
Exploratory total	**9**	**3.10**	8	3.62
Development				
Gas	**3**	**0.28**	8	1.85
Oil	**3**	**1.92**	3	3.00
Dry	**1**	**1.00**	-	-
Development total	**7**	**3.20**	11	4.85
Total	**16**	**6.30**	19	8.47

WHAT'S IN A NAME?

NET ASSET VALUE IS A KEY MEASURE OF AN OIL AND GAS COMPANY'S EFFECTIVENESS AND THE 2002 NAV PER SHARE FOR PURCELL INCREASED THREE PERCENT TO $4.62 REFLECTING THE SOLID VALUE IN RESERVES AND UNDEVELOPED LANDS THE COMPANY HAS ASSEMBLED.

Reserves, Asset Value and Finding Costs

Effective January 1, 2003, Gilbert Laustsen Jung Associates Ltd. (GLJ) conducted an evaluation of Purcell's reserves at Fort Liard and Martin & Brusset Associates (Martin) evaluated the reserves of the other areas. These same companies evaluated Purcell's reserves last year. The properties were evaluated on a reserve and economic forecast basis in accordance with the National Policy 2-B (Guide for Engineers and Geologists Submitting Oil and Gas Reports to Canadian Provincial Securities Administrators) definitions. The evaluators are qualified and experienced professional engineers and geologists and are independent of Purcell. The reserves evaluators rely on data generally available through public sources supplemented with data provided by Purcell which includes: land interest and lease descriptions, pertinent well data (such as well logs, drill stem tests, workover details, pressure surveys, production tests), geological mapping, property accounting statements, marketing arrangements, and operating and capital budget information.

Senior management oversees the review process by ensuring that the information provided to the evaluators is materially accurate and that the evaluators have not been restricted in any manner. The reserves reports are provided to the Board of Directors and reviewed as part of the corporate governance process.

Overall for 2002, proved reserves added replaced 49 percent of production during the year with total proved and probable reserves added replacing 73 percent of production. Reserve additions were achieved in Alberta at Birch Tar, Crossfield, Ells River, Rainbow and Sturgeon Lake and in Saskatchewan at Griffin, Weyburn and Minton. At Fort Liard, 5.4 bcf of proved reserves were transferred from producing to the non-producing category to take into account the need for another development well on the south structure of the property. Reserves will be returned to the "producing" classification in 2003 after the completion of the upgrade to the water handling facilities and the successful completion of the 2K-29 development well in early 2003. Total proved and total proved plus probable reserves at Fort Liard remained constant at December 31, 2002 compared to last year after allowing for production in 2002. At December 31, 2002, the value of established reserves, discounted at 10 percent per annum, at Fort Liard increased to $119 million (75.9 percent of total Company) from $110.7 million (81.6 percent of total Company) last year.

Reserves Reconciliation

Total proved reserves	Light & Medium Crude oil (mbbls)	Heavy Crude oil (mbbls)	NGL (mbbls)	Natural gas (bcf)	Equivalent (mBOE)
December 31, 2001	830	826	45	55.3	10,926
Revisions of previous estimates	(53)	63	(12)	(1.0)	(169)
Purchases	158	-	-	0.8	307
Dispositions	-	-	-	(0.1)	(23)
Extensions, discoveries and improved recovery	48	-	186	2.3	604
Production	(196)	(65)	(17)	(7.1)	(1,468)
December 31, 2002	787	824	202	50.2	10,177
Total proved plus probable reserves					
December 31, 2001	1,525	1,194	78	84.0	16,804
Revisions of previous estimates	(197)	7	(19)	(1.6)	(490)
Purchases	343	-	-	1.1	549
Dispositions	-	-	-	(0.1)	(23)
Extensions, discoveries and improved recovery	69	-	328	3.8	1,032
Production	(196)	(65)	(17)	(7.1)	(1,468)
December 31, 2002	1,544	1,136	370	80.1	16,404

Diluted net asset value, before tax, increased by 3.1 percent to $4.62 per share at December 31, 2002 as a result of higher commodity prices. The reserves value was determined by GLJ and Martin with escalated prices discounted at 10 percent per annum.

Net Asset Value at December 31, before tax

($ millions, except per share)	2002	2001
Proved and 50% probable reserves (disc. 10%)	**156.8**	135.7
Undeveloped acreage	**11.5**	6.5
Working capital (deficiency)	**(35.2)**	(21.4)
Seismic data	**9.0**	5.2
Long term debt	**(5.0)**	-
Future site restoration liability, disc. 10%	**(2.3)**	(1.5)
Net asset value	**134.8**	124.5
Net asset value per share - basic	**4.88**	4.70
- diluted	**4.62**	4.48
Common shares outstanding - basic	**27,641,039**	26,512,840
- diluted	**31,178,739**	29,215,540

Pricing Assumptions

The pricing forecasts presented below were prepared by Gilbert Laustsen Jung Associates Ltd. and by Martin & Brusset Associates as at January 1, 2003.

	GLJ Pricing (3)		Martin Pricing	
Year	Crude oil ($/bbl) (1)	Natural gas ($/mcf) (2)	Crude oil ($/bbl) (1)	Natural gas ($/mcf) (2)
2003	30.75	6.60	24.00	4.75
2004	25.00	5.45	22.00	4.25
2005	23.00	5.05	22.00	4.25
2006	23.00	5.05	22.10	4.34
2007	23.00	5.05	22.40	4.43
2008	23.00	5.15	22.70	4.52
2009	23.50	5.25	23.00	4.61
2010	23.25	5.35	23.30	4.70
2011	23.75	5.45	23.60	4.79
2012	24.00	5.55	24.00	4.89
2013	24.50	5.60	24.40	4.99
Thereafter	+1.5%/yr	+1.5%/yr	+2.0%/yr	+2.0%/yr

(1) West Texas Intermediate at Cushing, Oklahoma

(2) AECO

(3) GLJ pricing was updated April 1, 2003.

Finding and Development Costs

The four-year finding and development costs, excluding costs of $21.9 million incurred on undeveloped properties, are $10.35 per BOE using proved reserves and $8.50 per BOE using total proved and probable reserves. The finding and development costs for 2002, excluding costs of $7.4 million incurred on undeveloped properties, are $36.55 per BOE using proved reserves and $24.99 per BOE using total proved and probable reserves. Finding and development costs are significantly higher in 2002 as a result of facilities constructed at Rainbow, Alberta and modest reserve additions from drilling. In particular, the substantial up-front investment in infrastructure at Rainbow skews the finding and development costs for 2002 but places the Company in a strong competitive position for future activities in the area.

Finding and Development Costs

($ per BOE)	2002	Four Year Average
All-in costs		
Proved	46.88	12.95
Total proved and probable	31.95	10.63
Excluding costs on undeveloped properties (1)		
Proved	36.55	10.35
Total proved and probable	24.99	8.50

(1) Excluding certain costs aggregating $7.4 million in 2002 ($21.9 in the four year average) for undeveloped exploration acreage, seismic programs on undeveloped acreage, and costs paid by Purcell to construct facilities to process third-party gas at Fort Liard.

DEBT FINANCING

Management continues to strive to maintain conservative debt levels. The Company is forecasting that debt levels will reduce from a debt-to-cash flow ratio of 2.7-to-1 at December 31, 2002 to 1.3-to-1 by the end of 2003.

Bank Credit Facility

The Company's revolving demand credit facility was renewed during 2002 with the lending limit remaining unchanged at $35 million. The facility was renewed in August 2002 following a period of relatively low commodity prices. The Company expects to renegotiate the lending facility during the second quarter of 2003. Additional production coming on stream in the second quarter of 2003 should help to support a higher facility limit.

Subordinate Debenture

To provide additional funding for the ongoing capital program, the Company completed a $5.0 million subordinate debenture financing on October 18, 2002, as detailed in note 8 to the consolidated financial statements. It is likely that the Company will exercise its option to payout the debenture at the end of the first two years of the debenture term. Including the $412,575 calculated value of the warrants that were issued with the debenture, costs to secure the financing amounted to $817,656. These costs are being amortized to expense over the debenture term.

EQUITY

Flow-through Shares

During 2002, the Company issued 2,071,399 flow-through shares at $3.00 per share for gross proceeds of $6,214,197. The Company renounced, on December 31, 2002, exploration expenses, for income tax purposes, for the full amount of the equity issue. The Company is committed to spending the funds on qualified expenditures during 2003. The Company has consistently utilized the flow-through funding mechanism to finance a portion of its exploration program. The cost effectiveness of this financing method will be monitored as Purcell moves forward with its exploration and development program.

Normal Course Issuer Bid

The Company received regulatory approval on June 11, 2002 to make a normal course issuer bid to purchase for cancellation up to 2.3 million common shares of the Company during the period June 13, 2002 to June 12, 2003. During 2002, 1,230,200 common shares were purchased at a cash cost of $3 million ($2.45 per share). The issuer bid was commenced because management considered the transaction to be a reasonable investment for the remaining shareholders as the shares were trading, and still are trading, at a substantial discount to diluted net asset value.

Capital Structure

($ thousands, at December 31)	2002	2001
Bank debt and working capital deficiency	**35,176**	21,389
Long term debt	**5,000**	-
Accrued future site restoration liability	**1,657**	1,098
Shareholders' equity	**47,079**	44,764

Purcell shares trade on the Toronto Stock Exchange under the symbol PEL.

BUSINESS RISKS

Purcell is engaged in exploration and development activity that is subject to the same business risks as any participant in the energy industry. Ownership of common shares should be considered speculative. With a growth strategy that emphasizes exploration for oil and natural gas, Purcell encounters numerous risks that experience, knowledge and careful evaluation may not be able to overcome. There is no assurance that further commercial quantities of oil and natural gas will be discovered by Purcell.

Purcell's asset value is based on oil and gas reserves that are reviewed independently by Gilbert Laustsen Jung Ltd. (GLJ) for Fort Liard and by Martin Brusset & Associates (Martin) for the remainder of the asset base. The reserves reports, prepared effective January 1, 2003 by GLJ and Martin, represent an estimate of Purcell's interest in its reserves and the future net production revenue derived therefrom. It is important to note that reserves reports include assumptions about the productive capability of each reservoir and each well into those reservoirs. Being estimates, each well and reservoir could perform differently than estimated, significantly altering the net production revenue ultimately realized.

Commodity price volatility is a significant factor that affects the success of the Company. Purcell is subject to price fluctuations that it has hedged, from time to time, by entering into financial or forward sales contracts. This approach assures a level of capital available for reinvestment but does not ensure that Purcell will necessarily receive the highest possible price available. Through financial and forward sales collar contracts for its natural gas, Purcell has hedged approximately 34 percent of its forecast 2003 production at a minimum sales price of Cdn$27.70 per BOE. All of Purcell's crude oil production is currently sold at market prices and not contracted. A significant portion of Purcell's natural gas production generates revenue in US dollars. The Company has not hedged currency fluctuations and is therefore subject to the foreign exchange risk based on the exchange rate for the US and Canadian dollars.

Capital availability is required for Purcell to realize growth and represents another area of risk. Capital sources used by Purcell include cash flow, bank lines of credit and equity markets. The risks to cash flow levels stem from production sales volumes and prevailing commodity prices. Bank relationships and, in turn, economic conditions, determine the level of credit extended to the Company. Economic conditions and investor confidence influence the availability of equity financing.

Increasing competition in western Canada is adding to the cost of doing business and therefore, increasing the financial risk. Competition also extends to the availability of qualified, professional staff. As for any business, Purcell's continued success is dependent upon its ability to attract and retain experienced management. These areas of competition are not any different than those faced by any other active exploration and development company.

Environmental regulation is becoming increasingly stringent and costs and expenses of regulatory compliance are increasing. Purcell expects it will be able to fully comply with all regulatory requirements.

The political and economic risks of working in Canada are perhaps as reasonable as anywhere in the world. Canada may suffer economically in conjunction with the economic strain and political uncertainty affecting the US however, this issue is not considered to be significant for the petroleum producing sector in Canada.

OUTLOOK

Purcell experienced the risks of exploration in 2002, not only in terms of reserves found, but also in terms of timing. It takes a number of years to move exploration forward from concept through to realizing production. While 2002 was a year of intense activity with many opportunities being pursued, most are still in a stage of development without yet adding to production and cash flow. Purcell invested the capital it budgeted in 2002 but fell short of its production and cash flow targets. For 2003, the goal is to translate much of the exploration and development budget invested in 2001 and 2002 into production and cash flow additions in 2003 and thereafter. Early 2003 drilling and completions activity are reflecting this objective with production additions expected in the second quarter of 2003 to take production from fourth quarter averages of 3,745 BOE per day up to potentially 6,000 BOE per day by the end of 2003.

Purcell did meet its objective of broadening its production base and will continue to increase production from B.C., Alberta and Saskatchewan to augment its world-class play in the Northwest Territories.

For 2003, the Company intends to invest between $25 and $30 million and drill up to 13 net wells. The funding will come from cash flow, budgeted to be $28 million, as well as equity financing and debt.

Purcell is aiming for production averaging 5,200 BOE per day for 2003. The additions needed to reach that level are approximately an average of 1,500 BOE per day. Of these additions, 800 BOE per day should be contributed by Fort Liard, 500 BOE per day from development projects at Ells/Birch Tar, Minton, Rainbow, Sturgeon, Edson and Weyburn, and 200 BOE per day from exploration projects. Meeting our targets in 2003 depends only moderately on exploration success.

Auditors' Report

TO THE SHAREHOLDERS OF PURCELL ENERGY LTD.

We have audited the consolidated balance sheets of Purcell Energy Ltd. as at December 31, 2002 and 2001 and the consolidated statements of operations and retained earnings and cash flows for the years then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2002 and 2001 and the results of its operations and its cash flows for the years then ended, in accordance with Canadian generally accepted accounting principles.

Chartered Accountants

BDO Dunwoody LLP

Calgary, Alberta
March 21, 2003

Management's Responsibility for Financial Reporting

The accompanying financial statements and all information in the annual report are the responsibility of management. The financial statements have been prepared by management in accordance with the accounting policies outlined in the notes to the financial statements. Financial statements include certain amounts based on estimates and judgements. Management has determined such amounts on a reasonable basis in order to ensure that the financial statements are presented fairly, in all material respects. In the opinion of management, the financial statements have been prepared within acceptable limits of materiality and are in accordance with Canadian generally accepted accounting principles. The financial information contained elsewhere in the annual report has been reviewed to ensure consistency with that in the financial statements.

Management maintains appropriate systems of internal control. Policies and procedures are designed to give reasonable assurance that transactions are appropriately authorized, assets are safe-guarded and financial records are properly maintained to provide reliable information for the preparation of financial statements.

BDO Dunwoody LLP, the external auditors, conduct an independent examination of the financial statements in

accordance with generally accepted auditing standards in order to express their opinion on the financial statements. Their examination includes a review and evaluation of the Corporation's system of internal control and such tests and procedures as considered necessary to provide reasonable assurance that the financial statements are presented fairly.

The audit committee of the Board of Directors, with a majority of its members being outside directors, have reviewed the financial statements including notes thereto, with management and BDO Dunwoody LLP. The financial statements have been approved by the Board of Directors on the recommendation of the audit committee.

Jan M. Alston
President & CEO
March 21, 2003

Terry L. Lindquist
Chief Financial Officer

Consolidated Balance Sheets

As at December 31

	2002	2001
Assets		
Current		
Cash	$ 300	$ 563
Accounts receivable (Notes 3 and 12)	8,309,462	4,479,111
Prepaid expenses and deposits	594,499	435,426
Inventory	435,987	141,686
Current portion of loan receivable (Note 4)	210,880	-
	9,551,128	5,056,786
Loan receivable (Note 4)	525,608	-
Deferred financing costs (Note 8)	809,552	-
Deferred asset (Note 16)	387,821	-
Property, plant and equipment (Note 5)	101,250,900	78,073,419
	$ 112,525,009	$ 83,130,205
Liabilities and Shareholders' Equity		
Current		
Bank indebtedness (Note 6)	$ 30,703,065	$ 20,000,484
Accounts payable and accrued liabilities	13,740,816	6,439,622
Corporate taxes payable	283,580	95
Current portion of obligations under capital leases (Note 7)	-	5,462
	44,727,461	26,445,663
Subordinate debenture (Note 8)	5,000,000	-
Provision for future site restoration costs	1,657,000	1,098,000
Future income taxes (Note 10)	14,061,677	10,822,215
	65,446,138	38,365,878
Shareholders' Equity		
Equity instruments (Note 9)		
Common shares	42,238,862	40,172,852
Share purchase warrants	412,575	-
Preferred shares	128,000	128,000
	42,779,437	40,300,852
Retained earnings	4,299,434	4,463,475
	47,078,871	44,764,327
	$ 112,525,009	$ 83,130,205

Director *Director*

Consolidated Statements of Operations and Retained Earnings

		2002		2001
Revenue				
Revenues (Note 11)	$	25,816,136	$	30,253,587
Financial hedge gain		751,980		-
Interest and other income		108,442		152,311
		26,676,558		30,405,898
Expenses				
Production		7,879,766		6,392,797
Depletion, amortization and site restoration		12,614,000		10,220,000
Amortization of deferred financing costs		17,260		-
General and administrative, net		2,194,677		2,024,126
Interest		1,441,263		976,322
		24,146,966		19,613,245
Income before corporate taxes		2,529,592		10,792,653
Corporate taxes (Note 10)				
Capital taxes		466,151		292,442
Future income taxes		973,830		3,086,533
		1,439,981		3,378,975
Net income for the year		1,089,611		7,413,678
Retained earnings, beginning of year		4,463,475		1,993,305
Purchase price of common shares repurchased in excess of book value (Note 9)		(1,253,652)		(4,943,508)
Retained earnings, end of year	$	4,299,434	$	4,463,475
Earnings per common share - basic	$	0.041	$	0.294
- diluted	$	0.040	$	0.282

Consolidated Statements of Cash Flows

For the years ended December 31

	2002	2001
Cash flows from operating activities		
Net income for the year	$ 1,089,611	$ 7,413,678
Adjust for non-cash items:		
Gain on sale of marketable securities	-	(2,872)
Future income taxes	973,830	3,086,533
Depletion, amortization and site restoration	12,614,000	10,220,000
Cash flow from operations	14,677,441	20,717,339
Changes in non-cash operating balances		
Accounts receivable	(2,776,540)	2,726,734
Prepaid expenses and deposits	(159,073)	4,733,661
Inventory	(294,301)	45,403
Deferred pension asset	(387,821)	-
Accounts payable and accrued liabilities	6,166,172	(2,047,511)
Corporate taxes payable	283,485	(54,298)
	17,509,363	26,121,328
Cash flows from financing activities		
Payments from (to) Liard Resources Ltd.	(407,768)	6,862
Decrease in share purchase loans	-	73,250
Increase in deferred financing costs	(396,977)	-
Increase in debenture	5,000,000	-
Issue of common shares, net of related expenses	6,091,578	8,931,068
Repurchase of common shares	(3,013,588)	(7,815,836)
Issue of special warrants, net of related expenses	-	(65,050)
Repayment of capital leases	(5,462)	(79,287)
Increase in utilization of bank credit facilities	10,702,581	6,300,056
	17,970,364	7,351,063
Cash flows from investing activities		
Changes in non-cash working capital balances		
Accounts receivable	(646,043)	337,473
Accounts payable	1,135,022	3,181,290
Increase in loan receivable	(736,488)	-
Proceeds on disposition of marketable securities	-	118,699
Purchase of marketable securities	-	(22,233)
Purchases of property, plant and equipment	(38,357,216)	(39,764,985)
Proceeds on disposition of property, plant and equipment	3,124,735	2,671,680
	(35,479,990)	(33,478,076)
Decrease in cash	(263)	(5,685)
Cash, beginning of year	563	6,248
Cash, end of year	$ 300	$ 563
Cash flow from operations per share - basic	$ 0.554	$ 0.821
-diluted	$ 0.544	$ 0.789

01 Nature of Operations

The Company was incorporated on December 5, 1986 pursuant to the Alberta Business Corporation Act. Since inception, the Company's efforts have been devoted to the acquisition, exploration and development of oil and gas properties.

02 Summary of Significant Accounting Policies

The consolidated financial statements of the Company have been prepared by management in accordance with Canadian generally accepted accounting principles. The preparation of consolidated financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and accompanying notes. Actual results could differ from those estimates. The consolidated financial statements have, in management's opinion, been properly prepared using careful judgement with reasonable limits of materiality and within the framework of the significant accounting policies summarized below.

(a) Consolidation

The consolidated financial statements include the accounts of Purcell Energy Ltd. (the "Company") and its wholly-owned subsidiaries 421416 Alberta Ltd., 641294 Alberta Ltd. and 757382 Alberta Ltd. and the Company's proportionate interest in the accounts of Northcor Exploration Fund 1988 and Western Exploration Fund 1988.

(b) Inventories and revenue

Revenue is recognized on production and is net of transportation costs. Inventories of petroleum products, operating supplies and raw materials are valued at the lower of cost and net realizable value.

(c) Prepaid expenses and deposits

Prepaid expenses and deposits include deposits on forward sales contracts and deposits to secure pipeline space to deliver gas in future periods.

(d) Property, plant and equipment

The Company follows the full cost method of accounting for oil and gas operations whereby all costs of exploring for and developing oil and gas reserves are initially capitalized. Such costs include land acquisition costs, geological and geophysical expenses, carrying charges on non-producing properties, costs of drilling and overhead charges directly related to acquisition and exploration activities.

Costs capitalized, together with the costs of production equipment, are depleted on the unit-of-production method based on the estimated gross proved reserves. Petroleum products and reserves are converted to equivalent units of natural gas at approximately 6,000 cubic feet to 1 barrel of oil.

Costs of acquiring and evaluating unproved properties are initially excluded from depletion calculations. These unevaluated properties are assessed periodically to ascertain whether impairment has occurred. When proved reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of the impairment is added to costs subject to depletion calculations.

Proceeds from the sale of petroleum and natural gas properties are applied against capitalized costs, with no gain or loss recognized, unless such a sale would significantly alter the rate of depletion. Alberta Royalty Tax Credits are included in oil and gas sales.

In applying the full cost method, the Company performs a ceiling test which restricts the capitalized costs less accumulated depletion and amortization from exceeding an amount equal to the estimated undiscounted value of future net revenues from proved oil and gas reserves, as determined by independent engineers, based on sales prices achievable under existing contracts and posted average reference prices in effect at the end of the year and current costs, and after deducting estimated future general and administrative expenses, production related expenses, financing costs, future site restoration costs and income taxes.

(e) Joint venture operations

The majority of the Company's petroleum and natural gas exploration activities are conducted jointly with others. These financial statements reflect only the Company's proportionate interest in such activities.

(f) Environmental and site restoration costs

A provision for environmental and site restoration costs is made when restoration requirements are established and costs can be reasonably estimated. The balance of future salvage value of assets is netted against the future site restoration accrual. The site restoration costs are accrued on the basis of actual production. The accrual is based on management's best estimate of these future costs on the ratio of actual production to proved producing reserves.

(g) Marketable securities

Marketable securities are carried at the lower of cost and market.

(h) Flow-through equity instruments

Expenditure deductions for income tax purposes related to exploratory activities funded by flow-through share/warrants arrangements are renounced to investors in accordance with income tax legislation. The Company provides for the future effect on income taxes related to flow-through shares as a charge to share capital when the expenditures are incurred. No liability regarding future taxes is recorded on unexpended flow-through share capital.

(i) Financial instruments

The Company carries a number of financial instruments. It is management's opinion that the Company is not exposed to significant interest, currency or credit risks arising from these financial instruments. The fair values of these financial instruments approximate their carrying values, unless otherwise noted.

The Company periodically utilizes custom financial instruments to reduce its exposure to fluctuations in commodity prices. Such instruments are not used for trading purposes. Gains and losses on commodity price instruments are included in oil and gas sales on settlement.

(j) Measurement uncertainty

The amounts recorded for depletion and amortization of petroleum and natural gas properties and equipment and the provision for future site restoration and reclamation are based on estimates. The ceiling test is based on estimates of proved reserves, production rates, oil and gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes and estimates in future periods could be significant.

The financial statements include accruals based on the terms of existing joint venture agreements. Due to varying interpretations of the definition of terms in these agreements the accruals made by management in this regard may be significantly different from those determined by the Company's joint venture partners. The effect on the financial statements resulting from such adjustments, if any, will be reflected prospectively.

(k) Future income taxes

Effective January 1, 2000, the Company adopted the recommendations of the Canadian Institute of Chartered Accountants with respect to accounting for income taxes. The new method was applied retroactively without restatement of the prior years. Under the recommendations, the liability method of tax allocation is used, based on differences between financial reporting and tax bases of assets and liabilities. Previously, the Company followed the deferral method.

(l) Stock based compensation plan

Effective January 1, 2002, the Company adopted the recommendations of CICA Handbook Section 3870, Stock Based Compensation and Other Stock-Based Payments. This section requires that direct awards of stock and liabilities based on the price of common stock be measured at fair value at each reporting date, with the change in fair value reported in the statements of income and encourages, but does not require, the use of the fair value method for all other types of stock-based compensation plans. None of the Company's plans qualify as direct awards of stock or as plans that create liabilities based on the price of the Company's stock, and as a result, the implementation of the section has no impact on the consolidated financial statements. The Company has chosen not to use the fair value method to account for stock-based employee compensation plans, but to disclose pro-forma information for options granted after January 1, 2002. The Company records no compensation expense when options are issued to employees. Any consideration paid by employees on the exercise of the options is credited to capital stock.

(m) Employee benefit plans

The cost of employee pensions and other retirement benefits is actuarially determined using the aggregate actuarial cost method based on actuarial liability for projected benefits earned in respect of all service to the plan members' assumed retirement date. The expected return on plan assets is based on the fair value of those assets. The excess of any net actuarial gain or loss exceeding 10% of the greater of the benefit obligation and the fair value of plan assets is amortized over estimated average remaining service period of the remaining active employees.

(n) Per share amounts

Basic earnings per common share and cash flow from operations per common share are computed by dividing earnings and cash flow from operations by the weighted average number of common shares outstanding for the period. Diluted per share amounts reflect the potential dilution that could occur if securities or other contracts to issue common shares were exercised or converted to common shares. The treasury stock method is used to determine the dilutive effect of stock options and other dilutive instruments, in accordance with new standards approved by the Canadian Institute of Chartered Accountants.

(o) Deferred financing costs

Deferred financing costs relate to the subordinate debenture. These costs include the costs incurred to complete the debenture financing and the fair value of the transferable warrant. These costs are being amortized over the five year term of the debenture agreement.

03 Share Purchase Loans

Included in accounts receivable are loans of $182,500 (2001 - $182,500) due from directors and employees of the Company who are key members of the Company's management team. These loans were made for market purchases of stock of the Company. The loans are unsecured and bear interest at prime payable monthly. The employee loans are due on December 31, 2003.

04 Loan Receivable

On April 1, 2002 the Company sold 37.96% of its capacity rights in the Fort Liard pipeline to a Fort Liard-based third party for $1,850,000. Pursuant to the sale agreement, the Company provided $850,000 of financial assistance to the purchaser in the form of a loan receivable. The agreement calls for monthly payments of principal plus interest at an effective rate of 7.6% per annum and is due March 1, 2007. Principal payments are due as follows:

2003	$ 210,880
2004	188,395
2005	199,952
2006	137,261

05 Property, Plant and Equipment

	2002	2001
Cost		
Oil and gas properties		
Exploration, development and related equipment expenditures	$ 123,770,216	$ 92,147,932
Property costs, net of dispositions	17,209,740	13,720,837
	140,979,956	105,868,769
Furniture and equipment	710,588	589,294
Total cost	141,690,544	106,458,063
Less: Accumulated amortization and depletion	(40,439,644)	(28,384,644)
Net book value	$ 101,250,900	$ 78,073,419

During the year, approximately $868,000 (2001 - $702,000) of general and administrative costs were capitalized to oil and gas properties. As at December 31, 2002, costs of acquiring unproved properties in the amount of $19,979,000 (2001 - $12,500,000) were excluded from depletion calculations.

Included under property, plant and equipment are assets under capital lease at original cost of $Nil (2001 - $42,876) less accumulated amortization of $Nil (2001 - $10,352).

06 Bank Indebtedness

	2002	2001
Bank operating loan	$ 28,865,000	$ 2,585,000
Bank overdraft	1,838,065	2,415,484
Banker's acceptances	-	15,000,000
	$ 30,703,065	$ 20,000,484

During the year, the Company secured a new revolving credit facility of $35 million (2001 - $35 million) with a Canadian chartered bank. Interest is charged at the bank's prime rate plus 1/4% per annum on the bank-operating loan while the rate on the banker's acceptances approximates the prime rate. The facility is supported by a general security agreement and a hypothecation of a fixed and floating charge debenture in the amount of $50 million (2001 - $50 million) supported by oil and gas properties. The facility will be reviewed prior to May 31, 2003 and if not renewed, shall be converted to a term facility with a term not exceeding 5 years. It is the Company's belief that this facility will be renewed.

Effective January 1, 2002, the Company retroactively adopted the recommendations of CICA pronouncement EIC-122 whereby the demand loans have been reclassified, presented and disclosed as bank indebtedness in current liabilities.

07 Obligations Under Capital Leases

The Company had several agreements to lease oil and gas production equipment under a $750,000 credit facility with a Canadian chartered bank. These leases had implicit rates of interest varying from 5.28% to 5.66%. The following is a schedule of the aggregate future minimum lease payments under the terms of the leases:

	2002	2001
Total minimum lease payments	$ -	$ 5,508
Less deferred financing charges	-	(46)
Obligations under capital leases	-	5,462
Less current portion	-	(5,462)
	$ -	$ -

08 Subordinate Debenture

On October 18, 2002 the Company completed a $5 million debenture financing. The debenture is subordinated to the Company's bank revolving credit facility, has a term of five years and bears interest at 14 percent per annum payable monthly. No principal is payable during the first 2 years of the term. Purcell has the right to prepay the entire outstanding principal anytime after October 17, 2004 with payment of six months interest. The debenture holder has been issued a transferable warrant entitling the warrant holder to purchase, on or before October 18, 2007, 625,000 common shares of the Company at $3.25 per share. The value attributed to the warrants of $412,575 and other direct costs incurred on this debenture financing have been recorded as deferred financing costs. These costs are being amortized to expense over the term of the debenture.

09 Equity Instruments

Authorized

The authorized share capital of the Company consists of an unlimited number of:

Common voting shares;
Preferred non-voting shares issuable in series, rights to be determined on issue; and
Series I convertible preferred shares.

The common shares are entitled to dividends in such amounts as the directors may from time to time declare and, in the event of liquidation, dissolution or winding-up of the Company, are entitled to share pro rata in the assets of the Company.

The preferred shares rank in priority to the common shares as to the payment of dividends and as to the distribution of assets in the event of liquidation, dissolution or winding-up of the Company. Preferred shares may also be given such other preferences over the common shares as may be determined for any series authorized to be issued.

Issued

Common shares		2002		2001
	Number of Shares	Amount	Number of Shares	Amount
Balance, beginning of year	**26,512,840**	**$ 40,172,852**	24,569,440	$ 30,670,143
Issued in exchange for cash by private placements [net of share issue costs of $403,119 (2001 - $514,582) and future tax savings of $157,844 (2001 - $214 169)]	**2,071,399**	**5,968,922**	2,400,000	8,819,587
Issued on exercise of options	**287,000**	**280,500**	243,400	325,650
Issued on exercise of special share purchase warrants	-	-	1,500,000	3,229,800
Repurchase of shares under normal course issuer bid	**(1,230,200)**	**(1,759,936)**	(2,200,000)	(2,872,328)
Future taxes on renounced exploration expenses	-	**(2,423,476)**	-	-
Balance, end of year	**27,641,039**	**$ 42,238,862**	26,512,840	$ 40,172,852

During December 2002, the Company completed private placements for an aggregate of 2,071,399 flow through shares at a price of $3.00 per share for gross proceeds of $6,214,197. One senior officer of the Company purchased 2,000 of the flow through shares. The Company is committed to spending $6,214,197 on qualified expenditures by December 31, 2003. As of December 31, 2002, the Company has expended $Nil on qualified expenditures.

During 2002, the Company repurchased 1,230,200 of its common shares at a purchase cost of $3,013,588 resulting in a $1,253,652 reduction in retained earnings.

During 2001, the Company completed private placements for an aggregate of 1,600,000 flow-through shares at a price of $4.05 per share and 800,000 common shares at a price of $3.30 per share for gross proceeds of $9,120,000. The Company paid a 5% commission on the gross proceeds of the private placement. Liard Resources Ltd. ("Liard") purchased 500,000 shares out of the total 2,400,000 shares issued in the private placement. Liard is related by virtue of having common management. In addition, the Company also repurchased 2,200,000 of its common shares at a purchase cost of $7,815,836 resulting in a $4,943,508 reduction in retained earnings.

The weighted average number of shares outstanding for 2002 was 26,491,049 (2001 - 25,229,690). Subsequent to year end, the Company issued 1,000,000 shares pursuant to a private placement financing for gross proceeds of $2,900,000.

Share purchase warrants		2002		2001
	Number of Shares	Amount	Number of Shares	Amount
Balance, beginning of year	-	$ -	1,500,000	$ 6,042,175
Share purchase warrants				
Issued in the year	625,000	412,575	-	-
Less future taxes on renounced				
exploration expenses	-	-	-	(2,776,350)
Less: issue costs				
(net of future taxes of $29,025 in 2001)	-	-	-	(36,025)
	625,000	412,575	1,500,000	3,229,800
Share purchase warrants				
exchanged for common shares	-	-	1,500,000	3,229,800
Balance, end of year	625,000	$ 412,575	-	$ -

On October 18, 2002, the Company issued a transferable warrant pursuant to the subordinate debenture financing (Note 8). The warrant entitles the holder to purchase, on or before October 18, 2007, 625,000 common shares at $3.25 per share. The fair value of this warrant was estimated as $412,575 using the Black Scholes option-pricing model with the following assumptions: Dividend yield (Nil); expected volatility (0.34); risk-free interest rate (5.0%); and weighted average life of 5 years.

Preferred shares		2002		2001
	Number of Shares	Amount	Number of Shares	Amount
Balance, beginning of year	2,276	$ 128,000	2,276	$ 128,000
Balance, end of year	2,276	$ 128,000	2,276	$ 128,000

The preferred shares earn cumulative dividends at 5% and were convertible into 76,815 Common shares on or before December 31, 1997 at the option of the holder. No preferred shares were converted prior to December 31, 1997 so the conversion privilege has expired. The preferred shares are redeemable at $56.25 per share. Preferred shares dividends in arrears as at December 31, 2002 amounted to $47,565 (2001 - $41,165).

Options

The Company has a stock option plan under which employees; directors and consultants are eligible to receive grants. On December 31, 2002 4,000,000 (2001 – 4,000,000) common shares were reserved for issuance under the plan. Options granted under the plan generally have a term of five years to expiry and vest equally over a three-year period starting on the first anniversary date of the grant. The exercise price of each option equals or exceeds the market price of the Company's common shares on the date of the grant. At December 31, 2002, 2,912,700 options with exercise prices between $0.70 and $3.75 were outstanding and exercisable at various dates to the year 2007.

	2002		2001	
	Number of options	Weighted average exercise price	Number of options	Weighted average exercise price
Stock options, beginning of year	**2,702,700**	**$ 2.31**	2,425,100	$ 2.03
Granted	**637,000**	**2.57**	583,000	3.20
Exercised	**(287,000)**	**0.98**	(243,400)	1.34
Cancelled	**(140,000)**	**3.39**	(62,000)	3.36
Stock options outstanding, end of year	**2,912,700**	**$ 2.45**	2,702,700	$ 2.31
Exercisable, end of year	**1,914,532**	**$ 2.25**	1,581,798	$ 1.78

	Options outstanding			Options exercisable	
Range of exercise prices	Options outstanding	Weighted average remaining term (years)	Exercise price	Weighted average options exercisable	Weighted average exercise price
Under $1.00	487,000	0.6	$ 0.72	487,000	$ 0.72
$1.00 - $1.99	155,000	0.1	1.30	155,000	1.30
$2.00 - $2.99	1,239,700	3.2	2.61	709,533	2.69
$3.00 and over	1,031,000	3.4	3.25	562,999	3.29
	2,912,700	2.7	$ 2.45	1,914,532	$ 2.25

Pro Forma Disclosure

The Company does not record compensation expense when stock options are amended or issued to employees, as disclosed in Note 2(l). Had compensation expense been determined based on fair value at the option grant dates, net income and earnings per share would have been reduced to the pro forma amounts indicated below:

		2002 As Reported		2002 Pro Forma
Net income	$	1,089,611	$	1,048,945
Earnings per share, basic	$	0.041	$	0.040
Earnings per share, diluted	$	0.040	$	0.039

The fair value of share options was estimated using the Black-Scholes option-pricing model with the following assumptions: Dividend yield (Nil); expected volatility (0.60); risk-free interest rate (5.0%); and weighted average life of 5 years.

10 Corporate Taxes

The effective rate of income tax varies from the statutory rate as follows:

		2002		2001
Combined tax rate		**39.12%**		41.62%
Expected income tax provision at statutory rate	$	**989,576**	$	4,489,744
Differences due to resource deductions (recoveries)		**766,964**		(1,763,995)
Net effect of rate reduction		**(750,500)**		-
Other differences		**(32,210)**		360,784
Provision for large corporations and provincial capital taxes		**466,151**		292,442
Actual corporate tax provision	$	**1,439,981**	$	3,378,975

Subject to confirmation by income tax authorities, the Company has the following approximate undeducted tax pools:

		2002		2001
Cumulative Canadian Oil and Gas Property Expenses *	$	**10,628,000**	$	6,672,000
Cumulative Canadian Development Expenses *	$	**7,312,000**	$	6,516,000
Cumulative Canadian Exploration Expenses *	$	**15,572,000**	$	10,214,000
Undepreciated Capital cost	$	**27,460,000**	$	23,681,000
Non-capital losses carried forward for tax purposes available from time to time until 2006	$	**1,793,000**	$	3,471,000
Share issue costs	$	**833,000**	$	935,000
Net capital losses carried forward	$	**-**	$	57,000

These pools are deductible from future income at rates prescribed by the Canadian Income Tax Act.

* Certain tax pools acquired are successored and can only be used against income generated from certain properties.

The components of the Company's future income tax liabilities are a result of the origination and reversal of temporary differences and are comprised of the following:

Nature of temporary differences	2002	2001
Capital assets	$ 15,108,680	$ 12,648,081
Share issue costs	(345,453)	(389,006)
Unused tax losses carryforward	(701,550)	(1,436,860)
Future income tax liability	$ 14,061,677	$ 10,822,215

11 Revenues

	2002	2001
Petroleum and natural gas sales	$ 30,745,613	$ 37,471,511
Loss on restructuring natural gas sales contracts	-	(5,000,000)
Royalty revenue	41,748	71,893
Crown royalty expense	(4,510,419)	(2,006,884)
Freehold and overriding royalty expense	(712,272)	(486,655)
Alberta royalty tax credit	251,466	203,722
	$ 25,816,136	$ 30,253,587

During 2001, the Company expensed costs that were incurred pursuant to the cancellation of certain forward natural gas sales contracts. The costs were amortized against revenue over the original contract period of April 1, 2001 to November 1, 2001.

12 Related Party Transactions

During the year ended December 31, 2002, the Company:

(a) charged $27,768 of interest to Liard Resources Ltd. ("Liard");

(b) paid net loan payments of $407,768 to Liard; and

(c) charged $7,658 of interest on loans to employees and directors as detailed in Note 3.

During the year ended December 31, 2001, the Company:

(d) charged $26,137 of interest to Liard;

(e) received net loan payments of $6,862 from Liard; and

(f) charged $7,595 of interest on loans to employees and directors as detailed in Note 3.

Liard is a shareholder of the Company and is related by virtue of having common management. Included in accounts receivable is an amount due from Liard of $674,169 (2001 - $266,401). The balance earned interest at prime plus 1% per annum from January 1, 1998 to December 31, 2002.

These transactions are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

13 Commitments

(a) Office lease

The Company is committed to a lease agreement for office space expiring November 30, 2004. In addition to operating costs, the lease requires annual minimum lease payments as follows:

2003	$ 211,778
2004	194,647

(b) Natural gas

The Company has entered into financial contracts to hedge commodity prices and physical contracts to deliver natural gas. The terms of the contracts are summarized as follows:

Contract Type	Floor Price	Ceiling Price	Daily Volume	Contract Term
Financial	$4.15 per GJ at AECO	$5.70 per GJ	12,000 GJ	November 1, 2002 to November 1, 2003
Physical	$6.50 per GJ at AECO	$8.50 per GJ	7,000 GJ	November 1, 2003 to April 1, 2004

(c) Employment contracts

The Company has employment agreements in place where certain members of the management team will receive between 1 to 2 years salary for severance upon termination without cause. The current total commitment on termination is estimated to be approximately $1,330,000.

(d) Transportation

Pursuant to an agreement dated July 9, 2002, the Company secured certain space on the Fort Liard Valley Pipeline to transport natural gas. The agreement calls for the following payments to be made by Purcell:

2003	$ 580,798
2004	496,977
2005	490,968
2006	321,452

14 Financial Instruments

As disclosed in Note 2(i), the Company holds various forms of financial instruments. The nature of these instruments and the Company's operations expose the Company to interest rate, commodity price and industry credit risks. The Company manages its exposure to these risks by operating in a manner that minimizes its exposure to the extent practical.

(a) Interest rate risk management

The Company's bank indebtedness is subject to floating rates. The floating rate debt is subject to interest rate cash flow risk, as the required cash flows to service the debt will fluctuate as a result of changes in market rates.

As at December 31, 2002, the increase or decrease in net earnings before taxes for each 1% change in interest rates on floating rate debt amounts to approximately $307,000 (2001 - $200,000) per annum. The related disclosure regarding these debt instruments is included in Note 6 of these financial statements.

(b) Commodity price risk

The Company is subject to commodity price risk for the delivery of natural gas and crude oil under the contracts detailed in Note 13(b). The Company managed the risk by delivering natural gas and crude oil received in kind on behalf of the Company and several sub-participants from the operations of various joint ventures. The sub-participants are not involved in the contracts; however, the Company pays the sub-participants for their share of gas/oil sold at the prices received by the Company. The obligations to deliver under the contracts are the sole responsibility of the Company.

(c) Credit risk

A significant portion of the Company's trade accounts receivable are from working interest partners in the oil and gas industry and, as such, the Company is exposed to all the risks associated with that industry.

15 Statement of Cash Flows – Supplemental Information

	December 31 2002	December 31 2001
Interest paid	$ 1,438,571	$ 1,083,148
Corporate taxes paid	$ 182,666	$ 339,081
Cash proceeds on disposition of property, plant and equipment	$ 2,274,735	$ 2,671,680

16 Employee Benefits

Effective July 1, 2001, the Company initiated a strategy for the long-term retention of senior executives by the establishment of a Retirement Compensation Arrangement (RCA) plan governed by a trust agreement. The approximate amount of the future annual benefits is covered by insurance contracts. The Company funds the RCA fully with payments that are based on actuarial calculations.

Information about the Company's defined benefit plans, in aggregate, is as follows:

Pension benefit plans

		2002
Plan assets		
Fair value, at beginning of year	$	140,400
Actual return on plan assets, including mortality cost portion of insurance premiums		(106,348)
Employer contributions		400,900
Fair value, at end of year		434,952
Accrued benefit obligation		
Balance, at beginning of year		74,700
Current service costs		142,026
Interest cost		13,004
Actuarial gain		(16,691)
Balance, at end of year		213,039
Funded status – plan surplus		221,913
Unamortized actuarial loss		165,908
Accrued benefit asset, at end of year	$	387,821

The significant actuarial assumptions adopted in measuring the Company's accrued benefit obligation are as follows:

	2002
Discount rate	6.0%
Expected long-term rate of return on plan assets	6.0%
Rate of compensation increase	0.0%

The Company's net benefit plan expense is as follows:

		2002
Current service cost	$	142,026
Interest cost		13,004
Expected return on plan assets		(8,072)
Amortization of net accrual loss		4,512
	$	151,470
Recognition of prior year accrued benefit asset		138,391
Pension expense	$	13,079

17 Contingencies

The Company is subject to various regulatory and statutory requirements relating to the protection of the environment. These requirements, in addition to contractual agreements and management decisions, result in the accrual of estimated future removal and site restoration costs. These costs are accrued on the unit of production basis. Any changes in these estimates will affect future earnings.

Costs attributable to these commitments and contingencies are expected to be incurred over an extended period of time and are to be funded mainly from the Company's cash provided by operating activities. Although the ultimate impact of these matters on net earnings cannot be determined at this time, it could be material for any one quarter or year.

Five Year Summary

Years ended December 31

	2002	2001	2000	1999	1998
Revenues	**$ 25,816,136**	$ 30,405,898	$ 24,750,387	$ 6,137,650	$ 5,577,884
Cash flow	**14,677,441**	20,717,339	17,889,657	2,015,013	1,886,283
Per share - basic	**0.554**	0.821	0.730	0.088	0.096
Per share - diluted	**0.544**	0.789	0.697	0.084	0.093
Net income (loss)	**1,089,611**	7,413,678	8,225,838	247,013	(2,545,249)
Per share - basic	**0.041**	0.294	0.335	0.011	(0.130)
Per share - diluted	**0.040**	0.282	0.320	0.010	(0.110)
Working capital (deficiency)*	**(35,176,333)**	(21,388,877)	(6,223,753)	(4,406,544)	(4,911,319)
Long-term debt	**5,000,000**	-	5,462	84,749	308,504
Capital expenditures, net	**35,232,481**	37,093,305	22,103,819	6,637,469	5,504,255
Capital assets	**101,250,900**	78,073,419	50,847,114	32,393,722	27,423,253
Common shares outstanding	**27,641,039**	26,512,840	24,569,440	24,796,540	22,207,540
Shareholders' equity	**$ 47,078,871**	$ 44,764,327	$ 38,670,373	$ 27,349,429	$ 21,751,430

* Includes demand bank debt.

RESERVES					
Proved and probable at 10% discount ($000)	**$ 185,115**	$ 159,661	$ 178,521	$ 102,145	$ 63,736
Oil and liquids (mbbls)	**3,050**	2,797	2,236	2,519	1,420
Gas (bcf)	**80.1**	84.0	89.1	93.5	55
PRODUCTION					
Gas (mmcf/d)	**19.56**	24.46	10.71	3.68	4.87
Oil and liquids (bbls/d)	**763**	528	539	584	479
BOE/d	**4,022**	4,604	2,322	1,197	1,291
LAND HOLDINGS					
Net acres (undeveloped)	**189,552**	116,134	52,846	39,363	55,911
DRILLING (GROSS WELLS)					
Gas	**6**	14	3	2	6
Oil	**4**	5	–	2	5
Dry and abandoned	**6**	–	–	–	2
Total	**16**	19	3	4	13
DRILLING (NET WELLS)					
Gas	**1.26**	3.47	0.42	0.48	0.72
Oil	**2.92**	5.00	–	0.60	1.82
Dry and abandoned	**2.12**	–	–	–	.24
Total	**6.30**	8.47	0.42	1.08	2.78

Corporate Information

BOARD OF DIRECTORS

Jan M. Alston, B.A., LL.B.(1)
President & Chief Executive Officer
Purcell Energy Ltd.

Bernard A. Benning, MEd., MBA, CMA(2)
Vice President, College Services,
Bow Valley College

Bruce J. Murray, B.Comm.
Chief Operating Officer
Purcell Energy Ltd.

John A. Niedermaier, B.Sc., P.Eng.(1)(2)
Petroleum Services Executive

Ronald J. Will, B.Sc.(1)(2)
Chairman of the Board
Business Executive

(1) Member of Audit Committee
(2) Member of Compensation Committee

OFFICERS

Jan M. Alston, B.A., LL.B.
President & Chief Executive Officer

Bruce J. Murray, B.Comm.
Chief Operating Officer

Terry L. Lindquist, B.Comm., C.A.
Chief Financial Officer

Richard Fedoruk, M.Sc., P.Geol.
Vice President, Exploration

Lawrence Backmeyer, B.Sc., P.Eng.
Vice President, Engineering

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Trading Symbol: PEL

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STANDARD ABBREVIATIONS

bbl	barrel
bbls/d	barrels per day
mbbls	thousand barrels
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmcf	million cubic feet
mmcf/d	million cubic feet per day
bcf	billion cubic feet
BOE	barrel of oil equivalent (based on converting 6 mcf of gas to one barrel)
BOE/d	barrels of oil equivalent per day
GJ	Gigajoule

Certain information included in this annual report is forward-looking and is subject to important risks and uncertainties. The results or events predicted in these statements may differ materially from actual results or events. Factors which could cause results or events to differ from current expectations include, among other things: the impact of commodity prices; well production rates; drilling success; the timing of exploration and development activities; the ability of Purcell Energy to make acquisitions and/or integrate the operations of acquired businesses in an effective manner; general industry and market conditions and growth rates; international growth and global economic conditions, including interest rate and currency exchange rate fluctuations; stock market volatility; the ability of Purcell Energy to recruit and retain qualified employees; and the successful implementation of Purcell Energy's overall business strategy. For additional information with respect to certain of these and other factors, see the reports filed by Purcell Energy with the Canadian securities regulators. Purcell Energy disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

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